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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	DOCKET NO. 05-0315
	)	
For Approval of Rate Increases and Revised Rate Schedules and Rules.	)	

DIVISION OF CONSUMER ADVOCACY'S

DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS

Book 1 of 2

February 21, 2007

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PUBLIC UTILITIES COMMISSION

DIVISION OF CONSUMER ADVOCACY
Department of Commerce and
Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaii 96813
Telephone: (808) 586-2800

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of)	
HAWAII ELECTRIC LIGHT COMPANY, INC.)	DOCKET NO. 05-0315
Approval of Rate Increase and Revised Rate Schedules and Rules.)	

DIVISION OF CONSUMER ADVOCACY'S
DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS

Pursuant to the Proposed Revised Procedural Schedule adopted in Order No. 23153, the Division of Consumer Advocacy submits its **DIRECT TESTIMONIES, EXHIBITS, AND WORKPAPERS** in the above docketed matter.

DATED: Honolulu, Hawaii, February 21, 2007.

Respectfully submitted,

By *Cheryl S Kikuta*
CHERYL S. KIKUTA
Utilities Administrator
DIVISION OF CONSUMER ADVOCACY

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CA-T-1
DOCKET NO. 05-0315

DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: **Overall Revenue Requirement, Test Year Concept, Sales Revenues, Miscellaneous Revenues, Fuel & Purchased Power Adjustments, Other Production Operations and Maintenance Expense, Customer Accounts Expense, Customer Service Expense, Taxes Other Than Income Taxes, Income Tax Expense, Accumulated Deferred Income Taxes, and State Deferred Investment Tax Credits.**

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DIRECT TESTIMONY OF MICHAEL L. BROSCH

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael L. Brosch. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a principal and the President of Utilitech, Inc. The firm's business and my responsibilities are primarily related to special services work for utility regulatory clients, including rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses, and special investigations of utility operations and ratemaking issues.

Q. WILL YOU SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE IN THE FIELD OF UTILITY REGULATION?

A. I have prepared Exhibit CA-100 for this purpose.

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN REGULATORY ENGAGEMENTS BEFORE THE HAWAII PUBLIC UTILITIES COMMISSION?

A. Yes. I submitted written direct testimony on behalf of the Hawaii Department of Commerce and Consumer Affairs, Division of Consumer Advocacy ("Consumer Advocate" or "CA") in rate case proceedings involving Hawaii

Electric Light Company Docket No. 6999, Maui Electric Company Docket No. 7000, Hawaiian Electric Company Docket No. 7700, GTE Hawaiian Telephone Company Docket No. 94-0298 and The Gas Company Docket No. 00-0309. In addition to these rate case engagements, I assisted the Consumer Advocate in its analysis and Statement of Position preparation in Docket No. 97-0035 involving the sale of The Gas Company by Broken Hill Proprietary Company, Ltd., then in Docket No. 03-0051 involving the subsequent sale of The Gas Company by Citizens Communications Company ("Citizens") to K-1 USA Ventures, Inc. and more recently in the latest sale of the Gas Company by K-1 to Macquarie Infrastructure Company in Docket No. 05-0242. In addition, I was involved in and assisted with the Consumer Advocate's analysis and Statement of Position regarding the proposed sale of the Kauai Electric Division by Citizens in Docket Nos. 00-0352 and 02-0060 and the analysis and Statement of Position in the sale of Verizon Hawaii to entities controlled by the Carlyle Group in Docket No. 04-0140. Most recently, I submitted testimony addressing Hawaiian Electric Company's proposed Community Benefits Program in Docket No. 05-0146.

Q. ON WHOSE BEHALF ARE YOU NOW APPEARING?

A. I am testifying on behalf of the Hawaii Department of Commerce and Consumer Affairs, Division of Consumer Advocacy ("Consumer Advocate" or "CA") in this proceeding.

Q. WHAT ARE THE FUNCTIONAL AREAS OF THE CONSUMER ADVOCATE'S PRESENTATION IN THIS DOCKET, FOR WHICH YOU ARE DIRECTLY RESPONSIBLE?

A. My testimony explains the test year concept employed in this Docket as well as the development of the Consumer Advocate's recommended test year sales and associated revenue levels, non-fuel production O&M expenses, customer accounts O&M expenses, customer service O&M expenses and tax expenses includable in the revenue requirement under this concept. In a separately filed testimony designated CA-T-5, I discuss issues involving HECO's proposed cost of service allocation studies, proposed revenue distribution among rate classes, and certain rate design issues.

Q. HOW ARE THE CONSUMER ADVOCATE ACCOUNTING SCHEDULES ORGANIZED?

A. The Consumer Advocate's Accounting Schedules, organized within Exhibit CA-101, contain the revenue requirements calculations for HELCO's 2006 Test Year. This Exhibit is jointly sponsored with other witnesses testifying on behalf of the Consumer Advocate. The specific witness who is responsible for the proposed adjustments set forth on separate pages within Exhibit CA-101 is identified on the schedule. Throughout my testimony, I will refer to individual Consumer Advocate adjustments that I sponsor by indicating the Consumer Advocate "Accounting Schedule" or the "CA Adjustment Schedule" that corresponds to the testimony discussion.

An index appears as the first page of CA-101, which lists each Accounting Schedule with a brief description of the adjustments or other calculations contained in the Schedule. These Consumer Advocate Accounting Schedules are organized into sections, within the following overall framework:

- Schedule/Section A — Summary of Revenue Requirement
- Schedule/Section B — Rate Base and Rate Base Adjustments
- Schedule/Section C — Operating Income and Adjustments
- Schedule/Section D — Cost of Capital Summary (CA T-4)
- Schedule E — Reconciliation of CA and HECO filings

Within Sections B and C, individual Consumer Advocate accounting adjustments are set forth on separate Accounting Schedules in sequential order, such that Schedule B-1, Schedule B-2, etc. represent proposed rate base adjustments and Schedule C-1, Schedule C-2, etc. represent proposed income statement adjustments. Consumer Advocate Accounting Schedule B and Schedule C start with the Company's prefiled rate base and operating income positions, respectively, and then reflect the total adjustments proposed by the Consumer Advocate to derive the Consumer Advocate's proposed rate base and operating income recommendations.

Individual rate base adjustments sponsored by Consumer Advocate witnesses will be referenced as either "Schedule B-xx" or as "Adjustment B-xx" to indicate the corresponding Consumer Advocate Accounting Schedule where the adjustment calculations are presented. Similarly, specific operating income adjustments sponsored by Consumer Advocate witnesses will be referenced as either "Schedule C-xx" or as "Adjustment C-xx" to indicate the corresponding Consumer Advocate Accounting Schedule where the adjustment calculations are presented. Mr. Steven Carver (CA-T-3) sponsors many of the accounting schedules within Exhibit CA-101.

Mr. David Parcell (CA-T-4) is responsible for the Consumer Advocate's proposed overall cost of capital, as summarized at Accounting Schedule D and on line 4 of Revenue Requirement Schedule A. Mr. Joseph Herz (CA-T-2) is responsible for the energy cost calculations that underlie the fuel and purchased power adjustments and the proposed Energy Cost Adjustment Clause ("ECAC") rate used in CA Accounting Schedule C-2, as well as the fuel inventory recommendations summarized within CA Accounting Schedule B-5.

II. <u>OVERALL REVENUE REQUIREMENT</u>.

Q. WHAT IS THE CONSUMER ADVOCATE'S PROPOSED REVENUE REQUIREMENT FOR THE 2006 TEST YEAR?

A. Based on the analysis conducted by all of the Consumer Advocate's witnesses, HELCO's total rates and revenues should be increased by

$16.6 million, as set forth at line 9 in the "CA PROPOSED" column of Accounting Schedule A. This proposed revenue increase is based upon the Consumer Adovcate's proposed cost of capital that is sponsored by Mr. David Parcell (CA-T-4) and incorporates numerous other rate base and operating income adjustments sponsored either by Mr. Herz (CA-T-2), Mr. Carver (CA-T-3) or as explained herein, by me.

Q. WHAT IS THE ORIGIN OF THE BEGINNING VALUES USED IN THE CONSUMER ADVOCATE ACCOUNTING SCHEDULES?

A. Exhibit CA-101 uses the Company's prefiled Direct Testimony and Exhibits, as summarized in Exhibits HELCO-1601 (Rate Base) and HELCO-2101 (Results of Operations) sponsored by Ms. Ohashi and Mr. Lee, respectively, as the beginning values for revenue requirement calculations. From these beginning points, each Consumer Advocate adjustment set forth on the Schedules labeled B-xx and C-xx each represent a reconciling difference between the Company's position and the recommendations of the Consumer Advocate. A one-page summary listing and reconciling the many Consumer Advocate rate base and operating income differences to the Company's filing is set forth in Schedule E within the CA Accounting Schedules. The approximate revenue requirement "value" of the difference associated with cost of capital recommendations is also set forth at the top of Schedule E.

Q. WHAT ARE THE MAJOR ISSUES CONTRIBUTING TO THE MUCH LOWER REVENUE REQUIREMENT THAT IS RECOMMENDED BY THE CONSUMER ADVOCATE, RELATIVE TO HELCO'S PROPOSED INCREASE OF $29.9 MILLION?

A. The single largest issue is Cost of Capital, and is more fully addressed in Mr. Parcell's testimony. A summary of the revenue requirement issues include:

REVENUE REQUIREMENT ISSUE	EXH. CA-101 REFERENCE See Schedule E	APPROXIMATE ISSUE VALUE $ MILLIONS
Recommended Cost of Capital	D	$4.7
Keahole Plant Cost Exclusion	B-7, B-8, C-17, C-18	$4.2
Production O&M Expenses	C-3, C-4, C-5, C-6	$2.2
All Other Issues Combined		$2.2

Q. HOW IS THE BALANCE OF YOUR REVENUE REQUIREMENT TESTIMONY ORGANIZED?

A. Each topic or Consumer Advocate proposed adjustment that I sponsor is set forth in a separate section of testimony, as outlined in the Table of Contents set forth above.

Q. HOW DOES THE CONSUMER ADVOCATE PROPOSE THAT ITS REVENUE REQUIREMENT BE IMPLEMENTED, WITH RESPECT TO DISTRIBUTION AMONG RATE CLASSES AND RATE DESIGN?

A. I will respond to the Company's cost of service studies and rate design recommendations and will propose class distribution and rate design principles in a separately submitted Direct Testimony that has been identified as CA T-5.

III. TEST YEAR CONCEPT.

Q. WHAT IS THE PURPOSE OF A "TEST YEAR" WITHIN THE CONTEXT OF UTILITY RATE CASE PROCEEDINGS?

A. A test year is a period of time, usually including 12 contiguous months, that is adopted by a regulator to measure and compare the various data elements used to determine revenue requirement. It is common for the term "test year" to be used synonymously with the term "test period," and these terms have the same meaning in my testimony. The test year/period is used to populate the ratemaking formula, which consists of the following elements:

(Rate Base x Rate of Return) + Expenses = Revenue Requirement,

then

Revenue Requirement – Present Revenues = Rate Increase (Decrease)

The inputs to the formula are "Rate Base," a measure of the amount of capital invested in the business, a required "Rate of Return" expressed as a percentage earnings requirement on the rate base, "Expenses," including operations, maintenance, depreciation and taxes and "Present Revenues." The assembly of the HELCO's revenue requirement, combining each element of this formula, can be observed within CA-101, the CA Accounting Schedules A, B and C. It is critically important that representative values be determined for each of the key elements of the revenue change, the "Rate Base," "Rate of Return," "Expenses" and "Present Revenues" to reasonably determine the amount of required rate and revenue change. Accuracy in the determination of revenue requirement also requires that each element be comparable, which means that a uniform test period concept must be employed so that each element of the revenue requirement is properly matched.

Q. SHOULD A TEST YEAR BE REFLECTIVE OF THE PRECISE AMOUNTS OF COSTS LIKELY TO BE INCURRED DURING THE FUTURE YEARS WHEN NEW RATES WILL BE IN EFFECT?

A. No. Ratemaking is a periodic exercise, rather than a continuous process. The test year is not intended to accurately predict the future results of a utility. Each data element used to determine the revenue requirement is dynamic through time and can be expected to vary throughout the period the newly set utility rates remain in effect. For a growing electric utility, future sales and revenues, future expenses and future rate base investment levels will all likely, though not always, be larger in nominal terms. The use of a test year to quantify ratemaking values for these variables is intended to determine a revenue requirement based upon <u>the relationship between</u> revenue and cost levels at a common point in time, rather than the absolute values of test year revenues and costs. What is more important than absolute precision in ratemaking is that representative levels of ongoing revenues and costs are captured in a balanced way, within a consistently applied test year approach. Then, if future growth trends in revenues and costs prove to be somewhat offsetting, the approved rate levels will provide a reasonable opportunity for the utility to earn a fair return on investment.

Q. DO REGULATORY AGENCIES ALL EMPLOY THE SAME TYPE OF TEST YEAR?

A. No. Most regulatory jurisdictions use actual, historical test year data in rate case proceedings, while other states such as Hawaii employ projected or "future" test years. There is nothing inherently better about projected/future test years, relative to actual/historical test years, because the revenue change result being calculated is the result of <u>relationships</u> between the data elements, rather than the absolute value of revenues, expenses or rate base. For instance, if a utility is experiencing continually growing sales and revenues at the same time its rate base investment is growing and/or its expenses are growing, it may <u>not</u> be necessary to change rate levels – so long as revenue growth is sufficient to offset growing costs. This relative balance has apparently existed for HELCO for several years, since the Company has not required an overall revenue increase since Docket No. 99-0207, in which a 2000 test year was employed.

Q. WHAT MUST BE DONE IF A TEST YEAR CONTAINS UNUSUAL OR EXTRAORDINARY LEVELS OF REVENUES OR COSTS?

A. If unusual or extraordinary revenue, expense or rate base amounts occur within the test year, it is essential that adjustments be made to "normalize" such amounts so that revenue requirement measurements are based upon only normal, ongoing amounts that are representative of financial performance within the test year. If such normalization is not performed, utility rates may be set to continuously over or under-recover ongoing cost levels to the disadvantage of either ratepayers or shareholders. Notably, HELCO has made several "normalization" adjustments in its filing.[1]

Q. IS THERE ANOTHER CHARACTERISTIC OF THE TEST YEAR THAT IS IMPORTANT TO CONSIDER WITHIN RATE CASE PROCEEDINGS?

A.. Yes. A test year can be based upon either <u>average</u> rate base compared to operating income statement reflecting average prices and volumes for the test year – or it can be based upon <u>year-end</u> rate base balances compared to

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[1] For example,HELCO-533 summarizes 14 Production O&M Forecast "Normalization" Adjustments proposed by HELCO. Similar normalization adjustments are sponsored by other HECO witnesses.

year-end customer and sales/revenue levels, year-end employee headcounts and wage rates, year-end depreciation expenses, etc.

Q. PLEASE DESCRIBE THE TEST YEAR THAT HAS BEEN EMPLOYED BY HELCO TO DETERMINE ITS ASSERTED REVENUE REQUIREMENTS IN THIS DOCKET.

A. HELCO has developed its rate case filing using a calendar 2006 projected test year. Of importance is the fact that HELCO's proposed test year in this Docket is based upon average rate base, average customer and sales levels and, for the most part, average expenses.

Q. IF KNOWN INCREASES IN COST OCCUR NEAR THE END OF THE TEST YEAR, IS IT NECESSARY TO ANNUALIZE THE COSTS FOR AN ENTIRE YEAR IN ORDER FOR FULL COST RECOVERY TO BE POSSIBLE WITHIN THE NEWLY AUTHORIZED UTILITY RATES?

A. No. This is a commonly held misconception about the ratemaking process. There are expected to be significant increases in revenues after the mid-point of the average 2006 test year that may be more than sufficient to offset increasing future costs, such as the costs of adding new employees or the costs of increasing generating capacity to meet demand growth. It is important to resist the intuitive arguments to simply "fold in" known cost increases when there has been no corresponding effort to also account for demand and revenue growth that is expected to occur after the mid-point of the average test year.

As a point of reference, each one percent increase in HELCO electric sales volumes would contribute $1.7 million in additional gross margin (revenues less energy costs) that is available to help "pay for" increasing rate base or higher expenses.[2] Significant load growth is anticipated to continue into the future, providing additional revenues that HELCO can use to pay for increasing costs not explicitly included in the test year.[3]

Q. IS THERE A DIFFERENCE BETWEEN "NORMALIZING" ANY SPECIFIC REVENUE OR EXPENSE ELEMENT, IN CONTRAST TO "ANNUALIZING" THAT ELEMENT?

A. Yes. Normalizing entails the removal of an abnormality. For example, if projected test year expenses include an abnormally high expenditure level associated with power plant maintenance activity, it would be appropriate to "normalize" the cost of maintenance work activity to a more representative, ongoing cost level for this element of the revenue requirement. If not normalized, inclusion of excessively high or low test period costs would create

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2 Test year sales revenues at present rates of $323 million (HELCO-301), less fuel expense of $79 million (HELCO-401), less purchased energy costs of $99 (HELCO-545) million, less revenue taxes of $30 million (HELCO-1301) equals margin revenues of approximately $175 million. One percent growth in sales would therefore produce about $1.7 million in pretax profit margin that is available to offset increasing costs. Such margin growth would be higher at proposed rates, after implementing the rate increase requested in this Docket.

3 See HELCO-202, page 9.

an over or under-recovery of such costs in future periods when more normal cost levels are expected to be incurred.

Annualizing, in contrast, involves translation of transaction data at a single point in time into a full annual year equivalent "annualized' amount. For example, if the Company projects the addition of ten new employees in December of the calendar test year and desired inclusion of a full year of salary and benefit expenses for the ten new employees, it could factor-up the monthly expense data for the ten employees to include the new costs for a full year with an annualization adjustment. As another example, as demand for electricity continues to grow and HELCO adds 1,059 new customers between the mid-point and the end of the test year,[4] such growth cannot be considered abnormal. If an adjustment were made to fully consider sales and revenue levels at year-end, including the higher number of customers than is considered within the "average" level included in the Company's filing, that adjustment would also be an "annualization" adjustment. Annualization adjustments have the effect of transforming the point in time for test year measurement, from an average approach to a year-end approach.

4 HELCO response to CA-SIR-3.1, page 4, shows December 2006 average customer (bill) count at 76,417 versus June 2006 at 75,358, for a net gain of 1,059 customers.

Q. HOW HAS THE CONSUMER ADVOCATE TREATED ISSUES INVOLVING UTILIZATION OF AN AVERAGE VERSUS ANNUALIZED TEST YEAR IN THIS DOCKET?

A. Mr. Carver and I have maintained the basic average test year concept throughout our adjustments, so as to avoid piecemeal distortions in the revenue requirement determination that can occur if individual elements of the revenue requirement formula are selected for annualization treatment, while other elements are not similarly annualized. Sales and revenues, rate base, staffing levels and operating expenses are all quantified throughout the entire 2006 test year on an average basis, so as to properly match all elements in determining the revenue requirement.

IV. SALES AND REVENUES.

Q. HOW DID HELCO DEVELOP ITS TEST YEAR 2006 SALES AND REVENUE PROJECTIONS?

A. Mr. Beck (HELCO T-2) describes and sponsors the Company's projected test year sales of 1,148 gigawatthours ("GWH"), as set forth in HELCO-201. Mr. Beck explains in his testimony and in HELCO-202 the process through which residential and commercial sales volumes were projected, as well as certain adjustments made by the Company to Schedule P Large Power Service sales to normalize and update for known changes to the underlying

June 2005 forecast that was relied upon. The results of HELCO sales projections are summarized in HELCO-201 through HELCO-207.

The test year GWH sales volume projections, as sponsored by Mr. Beck in HELCO T-2, are then priced out to derive equivalent sales revenue dollar values at present and proposed rates by Mr. Young (HELCO T-3). Mr. Young employs certain assumptions about the distribution of projected test year 2006 GWH sales volumes and customer levels, to distribute such sales among the specific rate schedule demand and energy blocks, rate riders and to recognize other tariff provisions. Mr.Young explains this process in HELCO T-3, at pages 2 and 3.

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE SALES VOLUME PROJECTIONS SPONSORED BY HECO T-2?

A. No. GWH sales volumes projected by HELCO for the test year were developed on a reasonable basis using generally accepted methodologies that incorporate information about economic conditions, mathematical trending models and customer specific market information.[5] Because of the timing of filings in this docket, it is now possible to compare projected GWH sales volumes to the actual sales that were experienced by the Company in 2006.

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5 See HELCO-203 for a description of the Sales Forecast Process and HELCO-WP-202 where the results of different approaches are considered and compared.

Q. WAS THE COMPANY'S RATE CASE SALES FORECAST REASONABLY ACCURATE IN PREDICTING ACTUAL 2006 GWH SALES VOLUMES?

A. Yes. The following table presents a comparison of projected to actual sales, based upon sales information provided by HELCO in response to CA-SIR-3.1:

GWH Comparison **Rate Schedule**	**Forecast** **HELCO-201**	**Actual** **CA-SIR-3.1**	**Difference** **GWH**
Schedule R	435.4	440.0	4.60
Schedule G/J	452.9	436.4	(16.50)
Schedule H/K	17.2	16.4	(0.80)
Schedule P	238.1	247.4	9.30
Schedule F	4.4	4.4	-
TOTAL	**1,148.0**	**1,144.6**	**(3.40)**

As indicated by this data, actual residential Schedule R and large power Schedule P sales were slightly above forecasted levels, while commercial sales under Schedules G, J, H and K were below forecast. On an overall basis, actual GWH sales were slightly below test year forecasted levels.

Q. ARE THERE ANY KNOWN CAUSES FOR LOWER THAN PROJECTED COMMERCIAL SALES?

A. In the response to CA-SIR-3.1, the Company noted that, "[t]he destructive earthquake that occurred on October 15, 2006 may have had a significant impact on sales in the Waimea District, which was the area of the Big Island that suffered the most damage. The most obvious single impact of the earthquake was the subsequent closing of the Mauna Kea Beach Hotel in December due to structural damage to the hotel. It is HELCO's understanding that the hotel is still assessing the extent of repairs and renovations to be performed, but the customer currently estimates that it will remain[ed] [sic] closed for an additional 12-18 months...HELCO also noticed a sharp decrease in overall sales growth in the Waimea district during November, although strong sales growth resumed in December. It is not known what will be the long-term impact of the earthquake will be."

The comparison to actual sales in the table above is of limited value due to potentially significant, but difficult to measure earthquake impacts within the actual data. However, since actual sales are within 0.3 percent of projected sales in spite of any negative earthquake impacts upon sales, acceptance of the Company's proposed rate case forecast appears reasonable and conservatively generous to the Company at this time.

Q. IF YOU HAVE ACCEPTED THE COMPANY'S SALES VOLUME FORECAST, WHY IS THERE ANY NEED FOR A SALES REVENUE ADJUSTMENT, AS SET FORTH AT CA SCHEDULE C-2?

A. The Company's test year sales revenue estimates at present rate levels include the impact of a calculated test year Energy Cost Adjustment Clause ("ECAC"), calculated at 9.003 cents per KWH.[6] This pro-forma ECAC rate

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[6] See HELCO-303 at "ENERGY COST ADJUSTMENT FACTOR CURRENT EFFECTIVE RATES" and HELCO-305 where this amount is calculated.

was derived from the Company's fuel and energy cost simulation calculations, so as to synchronize energy costs with ECAC revenues at present rates.

CA Adjustment Schedule C-2 recalculates the ECAC revenues in the Consumer Advocate's revenue requirement presentation using a modified ECAC factor of 8.621 cents per KWH that is associated with the revised higher energy costs calculated by Mr. Herz at Exhibit CA-210. This Consumer Advocate revenue adjustment is necessary to properly synchronize the Consumer Advocate's calculated fuel and purchase power costs with the energy cost adjustment revenues that would be recoverable through the ECAC at the revised fuel and purchased energy cost levels. The related fuel and purchased power adjustments are discussed in a subsequent section of my testimony.

Q. AT HELCO T-3, PAGES 6 THROUGH 10, MR. YOUNG PROPOSES CERTAIN CHANGES TO THE CALCULATION OF THE ECA FACTOR AT PROPOSED RATES. WHAT IS THE CONSUMER ADVOCATE'S RESPONSE TO THESE PROPOSALS?

A. The Company's proposed changes to the ECA factor calculation, as discussed by Mr. Young, will be addressed in the testimony of Consumer Advocate witness Mr. Joseph Herz (CA-T-2).

Q. WHAT IS INCLUDED IN HELCO'S MISCELLANEOUS REVENUES FOR THE TEST YEAR?

A. Miscellaneous Revenues include various types of Non-sales Other Electric Utility revenues collected from customers for late payment charges, service establishment charges, field collection charges, returned check charges and other tariff terms and conditions, as summarized in HELCO-WP-710. Also included in Miscellaneous Revenues are rent revenues and other minor miscellaneous revenues, as summarized in HELCO-710.

Q. IS ANY ADJUSTMENT NECESSARY FOR HELCO'S PROPOSED TEST YEAR MISCELLANEOUS REVENUES?

A. Yes. CA Adjustment Schedule C-1 sets forth an adjustment for Service Establishment Charge revenues, to recognize that HELCO's projection of such revenues for the test year is understated. The Company charges a fee to new customers seeking to establish service. At HELCO WP-710, page 1, the Company's proposed level of Service Establishment Charges at $228,000 is compared to prior year actual revenue levels. Actual revenues for this service totaled $234,400 in 2005 and were running well ahead of forecasted levels as of August 2006. Therefore, in order to reflect a more reasonable level of activity, I propose to use the year-to-date August recorded revenues of

$165,900 as an indication of ongoing activity levels.[7] Schedule C-2 multiplies this year-to-date August value by 12/8 to factor it up to an annual level.

Q. ARE HELCO NEW CUSTOMER ADDITIONS CONTINUING TO RUN AT HIGH LEVELS IN 2006, SUCH THAT AN INCREASE IN SERVICE ESTABLISHMENT REVENUES IS JUSTIFIED?

A. Yes. In fact, in its response to CA-SIR-3.1, the Company stated, "HELCO did not expect the high level of growth in numbers of accounts that is reflected in the recorded numbers, and thus its test year forecast of average customer counts is lower than 2006 recorded customer counts in all rate schedules."

V. FUEL AND PURCHASED POWER EXPENSES.

Q. HOW HAS HELCO DETERMINED ITS PROPOSED FUEL AND PURCHASED POWER EXPENSES FOR RATEMAKING PURPOSES?

A. In its filing, the Company has calculated pro-forma fuel and purchased power expenses using a dispatch simulation program with input data associated with HELCO generating units, fuel prices, purchase power contracts and adjusted demand levels. These calculations were reviewed by Consumer Advocate witness Mr. Joseph Herz and are addressed in detailed within CA-T-2.

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7 HELCO response to CA-IR-317,part b.

Q. HOW ARE THE RESULTS OF MR. HERZ'S ANALYSIS INCORPORATED INTO THE CONSUMER ADVOCATE'S REVENUE REQUIREMENT?

A. CA Adjustment Schedule C-2 sets forth the ratemaking adjustments required to include adjusted fuel expense and purchased energy expenses based upon the analysis performed by Mr. Herz, as summarized in Exhibit CA-201. In Exhibit CA-210, Mr. Herz calculates the Energy Cost Adjustment Clause ("ECAC") factor that corresponds with the Consumer Advocate's test year fuel and purchased power expense levels, system heat rate and sales levels. This ECAC value is then used to calculate annualized fuel adjustment revenues at present rates, which are incorporated into CA Adjustment Schedule C-2 at lines 8 through 16 to properly synchronize ECAC revenues and the related energy expenses for the test year, as referenced in my earlier testimony regarding Sales Revenues. Finally, lines 17 through 21 calculate the incremental revenue taxes associated with the additional ECAC revenues to be collected at the higher CA-proposed fuel and energy cost levels.

Q. AT PAGES 16 THROUGH 18 OF HIS TESTIMONY, MR. LEE (HELCO T-1) TESTIFIES IN FAVOR OF CONTINUED UTILIZATION OF THE ENERGY COST ADJUSTMENT CLAUSE ("ECAC"). ADDITIONAL TESTIMONY ABOUT THE BENEFIT OF THE ECAC AND PROPOSED CHANGES TO THE ECA FACTOR APPEARS AT PAGES 4 THROUGH 11 OF MR. YOUNG'S TESTIMONY (HELCO T-3). IS THE CONSUMER ADVOCATE IN

AGREEMENT WITH HELCO THAT THE ECAC SHOULD CONTINUE TO BE EMPLOYED?

A. Yes. Mr. Herz is addressing ECAC issues and explaining the analysis conducted by the Consumer Advocate pursuant to Act 162 and he will respond to the referenced HELCO Direct Testimony on this subject, as well as the additional filing made by HELCO on December 9, 2006 pursuant to Act 162.

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE CONTINUATION OF THE ECAC TO PROVIDE HELCO WITH FULL RECOVERY OF CHANGES IN ENERGY COSTS?

A. No. However, it should be recognized that the ECAC effectively transfers operating risks associated with energy cost fluctuations to HELCO's customers. When the ratemaking cost of equity capital to be allowed HELCO is being considered, this transfer of commodity price risk exposure to customers should be found to directly reduce the business risk facing HELCO and its shareholders. In addition, the Commission must remain vigilant in monitoring HELCO fuel procurement and operational performance because of the diminished financial incentives that result from automatic rate recovery of fuel price changes.

Q. IS ANY MODIFICATION TO HELCO'S PROPOSED SALES HEAT RATE BEING PROPOSED BY THE CONSUMER ADVOCATE?

A. Yes, Mr. Herz is recommending that the Sales Heat Rate for future ECAC administration be revised, as shown in his Exhibit CA-216.

VI. NON-FUEL PRODUCTION O&M EXPENSES.

Q. BEYOND FUEL EXPENSES, ARE THERE OTHER EXPENSES ASSOCIATED WITH THE OPERATION AND MAINTENANCE OF THE COMPANY'S GENERATING UNITS?

A. Yes. Substantial amounts of expense beyond fuel costs are incurred to operate and maintain the Company's fleet of power production facilities. HELCO-502 identifies this fleet, with base load, intermediate and peaking facilities located at Puna, Hill, Shipman and Keahole stations and with smaller fossil-fueled, wind and hydro facilities at other locations distributed around the Big Island.[8] Non-fuel "Other" Production Operation and Production Maintenance ("O&M") expenses, are incurred for staffing and operating the Company's generating units and for the engineering, environmental and other administrative functions supportive of such operations. Production Maintenance expenses primarily consist of the labor and non-labor costs incurred to repair and maintain generating units and related generating plant facilities. Throughout this section of testimony, I will refer to "Production O&M"

8 HELCO-501 illustrates the geographic location of HELCO generation facilities.

expenses, intending this reference to refer to labor and non-labor expenses recorded in NARUC accounts 500 through 554, but excluding fuel expenses recorded in accounts 501 and 547.

Q. WHAT AMOUNT OF PRODUCTION OPERATIONS AND MAINTENANCE ("O&M") EXPENSE IS PROPOSED BY HELCO IN ITS RATE FILING?

A. HELCO-530 indicates that the Company's test year projected 2006 Production Operations Expense is $9,587,000 and projected Maintenance expense totals $13,453,000, for a total proposed non-fuel Production O&M expense level of $23,040,000.[9] HELCO's production O&M witness, Mr. Giovanni (HECO T-5), explains the operational issues, historical changes in production operations and the key assumptions employed in developing the forecast and various adjustments in considerable detail at pages 8-82 of his testimony.

Q. HOW DOES THE COMPANY'S PROPOSED TEST YEAR NON-FUEL PRODUCTION O&M EXPENSE LEVEL COMPARE WITH PRIOR YEAR ACTUAL EXPENSES?

A. The proposed levels of Other Production O&M Expense are considerably higher than recent prior years. However, actual 2006 expenses were also

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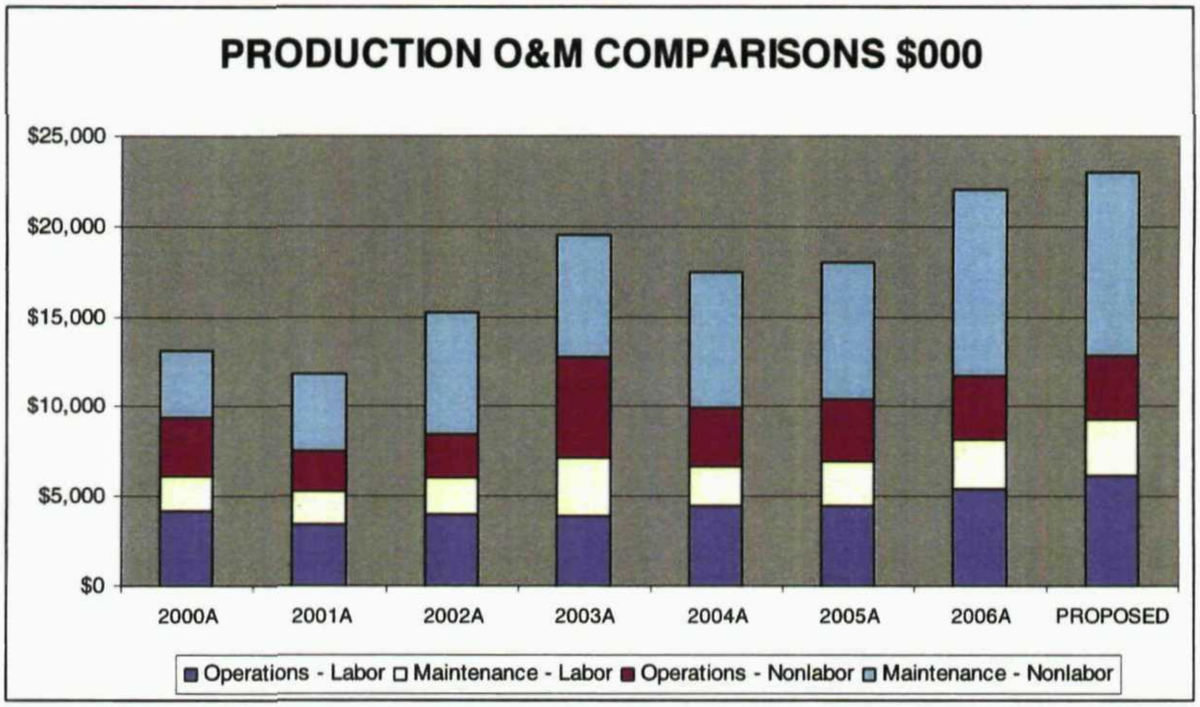
9 HELCO-531 summarizes a series of "budget" and "ratemaking" adjustments that reduce the initially forecasted 2006 production O&M forecast of $23,302,000 value by $262,000 (Budget Adjustment of -$357 plus Normalization of +$95,000). A listing of the "adjustments" and "normalizations" proposed by HELCO are set forth at HELCO-532 and HELCO-533, respectively.

much higher than in prior years and were only four percent below projected test year levels, as illustrated in the following graph:



Source: HELCO-534, HELCO-541 and CA-SIR-5.

The HELCO "Proposed" $23,040,000 level of Production O&M is higher than every historical year shown in the graph and exceeds the 2006 actual expenses that totaled $22,107,000. Notably, the 2006 spending amount represents the first time HELCO Production O&M expenses have exceeded $20 million and much of this spending was concentrated within the month of December 2006, suggesting that HELCO may have accelerated cost commitments at year-end to create favorable comparisons to its rate case forecast.[10]

Q. THE GRAPH IN YOUR PREVIOUS RESPONSE INDICATES AN INCREASING TREND IN PRODUCTION O&M EXPENSES, BUT WITH SUBSTANTIAL SPENDING VARIABILITY BETWEEN INDIVIDUAL YEARS. WHAT FACTORS CONTRIBUTE TO THE VARIABILITY IN PRODUCTION O&M EXPENSE LEVELS FROM YEAR-TO-YEAR?

A. The "bottom" two cost components in the graph represent operations and maintenance labor costs, which have been more stable and predictable than the non-labor expenses. Labor costs tend to vary directly with staffing levels and overtime spending. In 2003, all four expense categories (operations and maintenance / labor and non-labor) spiked upward due to the launch of HELCO's Generation Asset Management ("GAM") program in 2003, as more fully explained at T-5, pages 33 to 36 and the commencement of maintenance assessment consulting work and Asset Optimization ("AO") program initiated in 2003, as more fully explained by Mr. Giovanni in HELCO T-5 at pages 38 to 41.[11]

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10 CA-SIR-5, Attachment 1 at pages 7, 8, 12 and 14, indicates an extremely high level of non-labor expense in December 2006, relative to all prior months. This response was received just prior to finalization of testimony, so the Consumer Advocate was unable to discover the specific causes for higher expenses in December.

11 See HELCO responses to CA-IR-49 and 399 for additional details regarding the GAM program and CA-IR-51 as well as HELCO-522 and HELCO-528 for additional details regarding the AO program.

Close inspection of the data underlying the graph will reveal that much of the remaining variability in annual Production O&M expenses is driven by changes in the scope and scheduling of overhauls on the Company's generating units each year. In recognition of the importance of smoothing and normalizing maintenance work scoping for ratemaking purposes, to ensure that the test year does not include extraordinary spending on discrete projects that are not representative of normal, ongoing activity levels, HELCO has proposed a series of adjustments and normalizations that mostly relate to discrete maintenance projects, as listed in HELCO-531 and HELCO-532.

Q. WHAT WAS DONE BY THE CONSUMER ADVOCATE TO INVESTIGATE THE COMPANY'S PROPOSED LEVEL OF 2006 TEST YEAR PRODUCTION O&M EXPENSE?

A. The Consumer Advocate's analysis focused upon developing an understanding of the forecasting procedures and assumptions employed by the Company to quantify projected O&M levels. Detailed workpaper analyses prepared by the Company were requested in CA-IR-1 and CA-IR-2 for all witnesses, including the support for Production O&M levels sponsored by HELCO witness T-5. After reviewing these supporting calculations and support documentation, on-site interviews were conducted to discuss the Company's generating facilities and the source data, assumptions and procedures employed by the Company to develop its rate case expense forecasts. I also toured several HELCO generating facilities with Company personnel and submitted detailed information requests to clarify the basis for specific expense forecast elements. As a result of this work and numerous follow-up information requests, the Company has conceded that several mistakes or omissions need to be corrected as revisions to the HELCO proposed test year Production O&M levels.

Q. HAVE YOU REFLECTED THE REVISIONS THAT HELCO HAS INDICATED SHOULD BE MADE TO ITS PROPOSED TEST YEAR PRODUCTION O&M EXPENSE?

A. Yes. CA-101, Schedule C-3 sets forth the Company's conceded adjustments to proposed test year Production O&M expense, as summarized in the response to CA-IR-447, T-5, Attachment 1, page 2. These conceded adjustments relate primarily to responses provided to specific Consumer Advocate inquiries seeking supporting information where detailed expense forecast elements were not consistent with historical cost levels or with current overhaul work plans, as described in additional detail in the many IR responses referenced within the response to CA-IR-447, Attachment 1. The combined effect of these adjustments is a reduction in test year Production O&M of approximately $1.3 million.

Q. AFTER POSTING THE CONCEDED ADJUSTMENTS TO THE COMPANY'S PRODUCTION O&M EXPENSE PROJECTIONS FOR THE TEST YEAR, HAVE YOU ACCEPTED THE REMAINDER OF THE HELCO-PROJECTED PRODUCTION O&M EXPENSES?

A. No. The test year forecast includes modestly overstated Production O&M labor expenses and only two small correcting adjustments were conceded by HELCO with respect to labor expenses. Further downward adjustments to labor expenses for Production O&M are required. In addition, I propose two adjustments to non-labor Production O&M, to correct overstatement of estimated miscellaneous materials expenses and to remove speculative cost estimates for assumed low pressure turbine ("LPT") replacements, as more fully described in the following testimony.

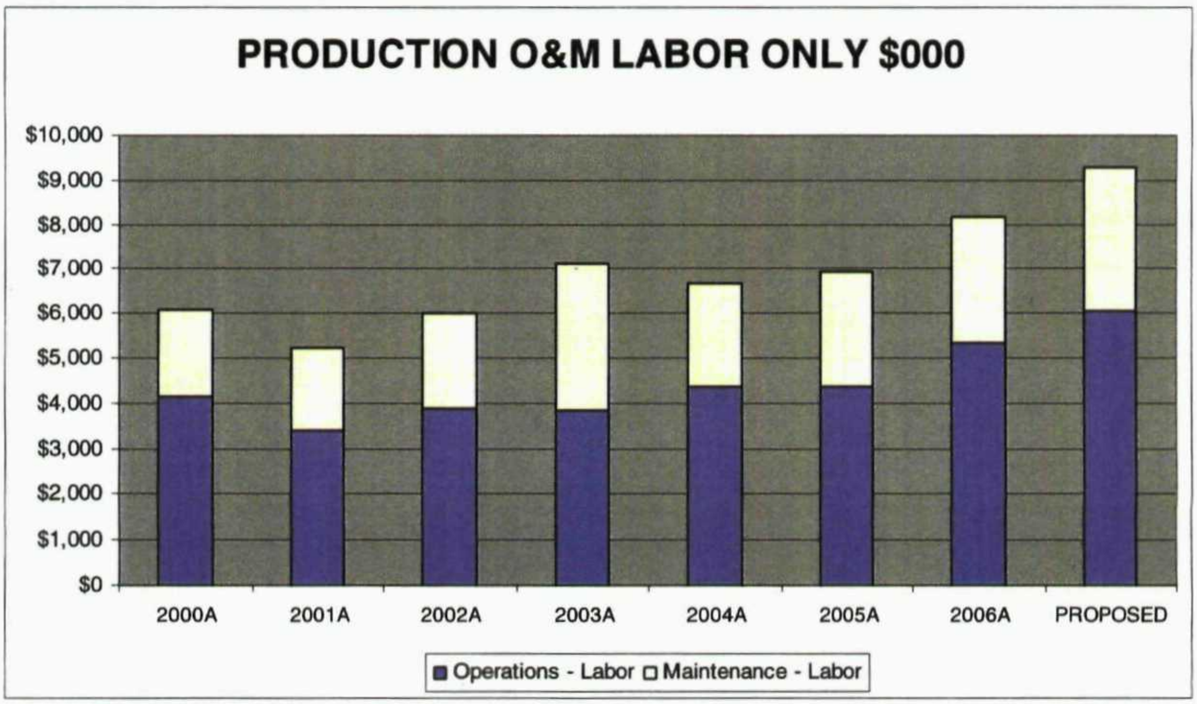
A. PRODUCTION O&M LABOR EXPENSE.

Q. WHAT IS HELCO'S ESTIMATED LEVEL OF PRODUCTION O&M LABOR EXPENSE FOR THE 2005 TEST YEAR?

A. As shown at HELCO-531, HELCO's estimated labor expense for Production Operations and Maintenance for the 2006 test year amounts to $6,054,000 for Operations and $3,228,000 for Maintenance.

Q. HOW DOES HELCO'S TEST YEAR PROJECTED PRODUCTION O&M LABOR COMPARE TO HISTORICAL ACTUAL AMOUNTS FOR SUCH LABOR EXPENSES?

A. Actual Production labor expenses have been gradually increasing from 2000 through 2006. As shown in the following table, the Company's test year "PROPOSED" Production labor expense projection for the test year is considerably higher than comparable actual Production Operations expenses actually incurred in 2006 and historically:

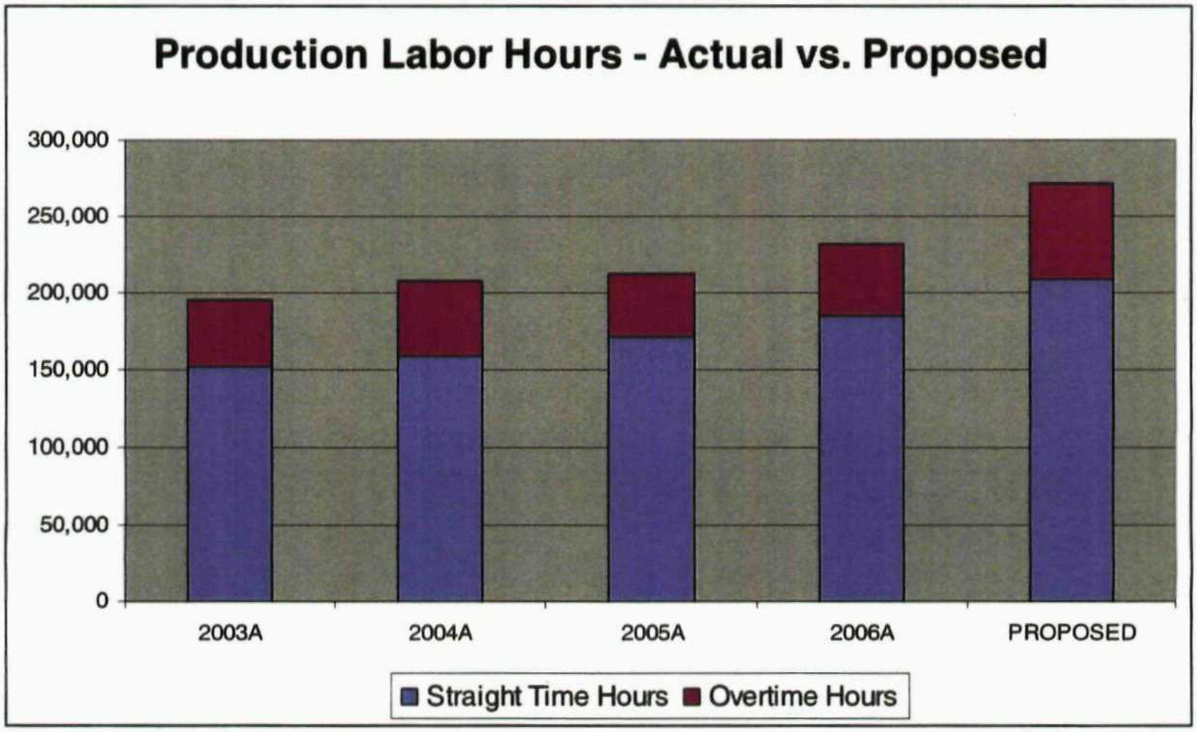


Source: HELCO-534, HELCO-541 and CA-SIR-5.

From this historical information, one can observe that Production labor expenses in the "PROPOSED" column on the far right exceed 2006 Actual labor expense levels by approximately $1.1 million or about 12 percent and also exceed all prior years shown.

Q. ARE PRODUCTION LABOR EXPENSES A FUNCTION OF BOTH THE QUANTITIES OF LABOR PROJECTED FOR THE TEST YEAR, AS WELL AS CHANGES IN WAGE RATES FOR COMPANY PERSONNEL?

A. Yes. Wage rates paid by HELCO tend to gradually increase, but the cause of the much larger 12 percent labor cost variance in 2006 actual versus HELCO's "PROPOSED" labor costs is largely attributable to the quantities of labor that were estimated by HELCO. This issue can be observed by comparing expensed Production labor hours projected for the test year to actual labor hours data for 2006 and previous years, as shown in the following graph.



Source: CA-SIR-11 (Proposed Amounts Corrected per CA-IR-447)

As in the case with total labor dollars, total labor hours have been gradually trending upward, but the Company's "PROPOSED" labor hours far exceed the actual 2006 and prior year levels. This "PROPOSED" hours include estimated labor levels for power plant operators and support personnel and for maintenance personnel, based upon certain ambitious staffing and overtime assumptions that are explained in HELCO T-5, at pages 60 through 69 (operations labor) and pages 72 to 79 (maintenance labor).

Q. SHOULD THE COMMISSION APPROVE HELCO'S PROJECTED PRODUCTION O&M LABOR EXPENSE LEVEL FOR THE 2006 TEST YEAR?

A. No. HELCO's forecasted test year Production labor expenses are overstated, for several reasons. First, HELCO has assumed significantly increased staffing levels with no vacancies at any of the authorized position, resulting in an overstated headcount because of recurring vacancies caused by normal employment turnover and delayed hiring of replacement personnel. Then, projected labor costs are further overstated because of the assumption that newly created positions would be filled and remain filled throughout all 12 months of the test year, effectively annualizing the increasing headcounts in a manner not consistent with the use of an average test year. To compound these problems, HELCO has also overestimated Production Department overtime levels, through reliance upon historical overtime ratios that existed at lower staffing levels in prior years and by rounding up the historical overtime ratios used in developing the rate case labor forecast. In the testimony that follows, I will explain the problems contributing to HELCO's overstatement of Production Department labor hours and expense in greater detail.

Q. WHAT IS THE PURPOSE FOR CONSUMER ADVOCATE ADJUSTMENT SCHEDULE C-4?

A. This adjustment has the effect of reducing the Company's projected levels of 2006 Production O&M labor expenses downward to actual 2006 recorded levels. The adjustment is reduced at line 5 to account for the correcting adjustments already conceded by HELCO that were recognized at Schedule C-3 and that impact labor. Further reduction to the adjustment at line 6 is to recognize that the HELCO Production Department actually incurred significant temporary service labor costs during the test year that were not forecasted due to the assumption of full staffing at higher levels.

Q. WHY SHOULD THE RATE CASE PROJECTIONS OF PRODUCTION O&M LABOR BE REDUCED TO ACTUAL LEVELS?

A. As explained in this testimony, HELCO's projected levels of test year Production O&M labor are overstated and should be corrected. HELCO has not demonstrated any reasonable factual basis for the dramatically increased estimated labor hours and costs projected for the test year. Notably, HELCO has not required the level of labor hours for actual operations that were projected for the test year. HELCO has not filled all of the projected positions that were assumed to be filled throughout the test year and has not required the level of overtime hours that were projected.

In contrast, the actual 2006 labor hours and expenses that were incurred by the Company were clearly adequate to provide safe and adequate service throughout the test year, as evidenced by the fact that the Company was able to meet Big Island customers' demands throughout the year while demonstrating improved generating unit reliability results as more fully explained in HELCO T-5, at pages 20 through 41 and in HELCO-514 through HELCO-518.

Q. TO DETERMINE STAFFING NEEDS FOR THE TEST YEAR, DID HELCO EMPLOY ANY SPECIFIC MEASUREMENT OF WORK REQUIREMENTS?

A. No. There are no objective measures of work requirements available, other than tracking of the number of hours actually incurred historically to operate and maintain the Company's generating facilities. The Company's rate case estimation of test year staffing levels and overtime hours appears to have been based largely upon subjective judgments about work requirements, without much regard to the historical hours and costs that were incurred in the past. The labor hours graph presented above clearly indicates that HELCO has overstated work requirements in relation to the actual hours required for production personnel in 2006 and prior years.

The Company's test year rate case staffing plan included nine (9) dedicated new operations positions at the Shipman Station (See HELCO-535) in 2006 and four (4) new maintenance positions spread across three locations (See HELCO-542), for a total of thirteen (13) new positions, above and beyond the 2005 actual staffing. This plan assumed full employment of a total of 101 Production Department employees, representing a 15 percent increase in staffing over the 88 total employees that were adequate to meet work requirements in 2005.

According to Mr. Giovanni's (HELCO T-5) explanation of Operations labor increases at page 65, the nine (9) new employees at Shipman are intended to "maximize" the availability of Shipman by "...increasing the staffing levels at Shipman Station from 100% overtime to 14 eight hour shifts per week to increase the availability of the Shipman units." According to Mr. Giovanni, Shipman Power Plant has been operated in the past by operators from Hill Power Plant and Puna Steam Plant that worked overtime. However, even after adding the new Shipman personnel into the rate case forecast, overall overtime hours inexplicably were increased rather than being reduced in the rate case forecast.[12]

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12 According to CA-SIR-11, actual overtime in 2004 was 15,839 hours at Hill and 7,288 hours at Puna; in 2005 overtime was 12,197 hours at Hill and 6,882 at Puna, the years when operators from these stations were used to staff the unmanned Shipman plant on an overtime basis. After assuming new permanent staffing at Shipman to remedy this situation in the rate case, the test year projected overtime levels for Hill and Puna did not decline and are still estimated at 15,580 and 7,000 hours, respectively.

With respect to Production O&M <u>Maintenance</u> labor projections, Mr. Giovanni's testimony at page 75 states, "[t]he maintenance staffing levels forecasted were based on the numbers of specific trades and craft personnel required to keep up with anticipated increased workload requirements." However, in its response to CA-IR-66b, the Company admitted that "[d]ocuments do not exist to quantify overall "work to be done" in 2006 pursuant to the forecast, in comparison to measures of amounts of work that was done in 2004 or in 2005." Similarly, on page 76 Mr. Giovanni referenced "backlog" as "a general term used to identify work that requires an outage and that is held in abeyance until it can be scheduled as part of an upcoming MO [maintenance outage] or PO [planned outage]." However, when inquiry was made by the Consumer Advocate to analyze whether maintenance "backlog" was increasing due to staffing constraints, the Company responded to CA-IR-76 stating, "'[b]acklog' statistics are not tracked and/or available in a useable format for analysis purposes."

Q. DID THE COMPANY ACTUALLY ACHIEVE STAFFING AT THE 101 EMPLOYEE LEVEL THAT WAS INCLUDED IN THE RATE CASE FORECAST FOR 2006?

A. No. Mr. Giovanni states at page 69 of HELCO T-5 that, "[t]he 2006 test year operations staffing level will be achieved by May 2006" and at page 72 he states, "[b]y year-end 2006, Kanoelehua and Keahole station maintenance will be fully staffed."[13] However, actual staffing for Production Department personnel has ranged from a low of 85 employees at year-end 2005 to a high level of 97 employees that occurred in July and August of 2006.[14] The average actual Production Department staffing levels since May of 2006 has averaged only 96 employees, not the 101 employee rate case forecasted level under the Company's no vacancy forecasting assumption.

Q. WHAT IS WRONG WITH HELCO'S RATE CASE ASSUMPTION THAT ALL AUTHORIZED EMPLOYEE POSITIONS WILL BE FILLED THROUGHOUT THE TEST YEAR?

A. Several things are wrong with this assumption. First, it is impossible to achieve full staffing at all times for any large business. Employees leave for many reasons, including retirement, illness, injury, spouse relocation and other personal reasons, often without much notice to the employer. Upon learning of a vacancy, the employer must then work around the vacancy by rescheduling work and initiating the process to solicit, interview, hire and train replacement personnel. With a planned workforce of about 101 in the Production Department, it would be very typical for several positions to be vacant at any point in time due to normal turnover of personnel. Mr. Giovanni attempts to dispute this notion of normal, structural vacancies in the workforce

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13 These are the locations where staffing increases were proposed. See HELCO-535 and HELCO-542.

14 CA-SIR-43, page 2.

by stating, at page 73, "[w]hat is different today versus in the past is that when separations are known in advance, recruitment to fill the pending vacancies is requested and approved as soon as possible to provide as much lead time and/or overlap as possible." But there is no denying the fact that HELCO has not achieved full employment at rate case proposed levels in 2006.

Second, HELCO has not reduced the overtime forecast to coincide with its new "full employment" assumption at the 101 position rate case workforce level. The Company should not be allowed to have it both ways, claiming new employees are needed to reduce overtime levels,[15] and then not reducing test year proposed overtime after including the labor and related employee costs for the new employees in the test year revenue requirement.[16]

Finally, HELCO has not reduced contractor charges to reflect any displacement of work done in the past by non-employees, to recognize projected increases in internal staffing levels for rate case purposes. Mr. Giovanni argues at page 61 that, "[v]acancies do not result in reduced costs because the work has to be done, either by other employees working overtime (see HELCO-536, 537, 538, 539) or contractors (see discussion below)." However, after forecasting for new employees, HELCO has not

15 See T-5, page 61, lines 13-22.

16 Test year Production Department overtime labor hours in the test year are forecasted at 62,010 hours according to CA-SIR-11, a level that far exceeds the 42,463 overtime hours actually incurred in 2005 and the 48,497 overtime hours actually incurred in 2004. HELCO-539 provides comparable overtime hours data, but has been corrected and superseded by revisions made in responding to Consumer Advocate discovery, as set forth in CA-SIR-11.

reduced contractor costs in the test year non-labor forecasts. HELCO has projected higher, rather than lower non-labor Operations expenses for the test year, stating "[t]he estimate is reasonable because it was derived form a review of the resources required to operate HELCO's generating units reliably and efficiently while complying with all environmental and other regulatory agencies."[17] HELCO has also projected an increase, rather than reduction, in test year non-labor Maintenance expenses, as shown at HELCO-541, with such costs projected to exceed 2005 actual levels by 32 percent.[18]

Q. DOES THE CONSUMER ADVOCATE'S ADJUSTMENT RESTATING PRODUCTION O&M LABOR EXPENSES TO ACTUAL COST LEVELS TAKE CARE OF THE COMPANY'S OVERSTATEMENT OF HEADCOUNTS, AS WELL AS OVERTIME HOURS?

A. Yes. Actual 2006 labor expenses are based upon the amount of labor actually incurred by HELCO to operate and maintain the generation facilities during the test year. Any tradeoffs that occurred between employment levels and overtime levels are implicitly included within the actual wage expense data. Overall, the labor hours and labor dollars incurred on an actual basis in 2006 are more consistent with the long term trends toward gradually increasing

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17 See HELCO T-5, page 71 and HELCO-534, where a 3.1 percent increase in Operations non-labor expense over 2005 actual levels is projected.

18 HELCO has since revised this estimate, conceding that several elements of its projected non-labor expenses are overstated and require downward adjustment, as discussed herein and summarized in CA-101, Schedule C-3.

Production Department labor expense levels and are reasonable for ratemaking purposes. More importantly, the Company has demonstrated its ability to provide safe and reliable service during 2006 at the level of labor costs allowed by the Consumer Advocate, after correcting for the overstatements in the Company's rate case forecasts and adjusting such costs to actual levels.

B. PRODUCTION O&M NON-LABOR EXPENSE.

Q. WHAT IS THE PURPOSE OF CONSUMER ADVOCATE ADJUSTMENT SCHEDULE C-5?

A. This adjustment reduces the Company's forecasted Production O&M miscellaneous materials expenses to better comport with historical average actual cost levels. Schedule C-5 displays actual annual expenses associated with miscellaneous materials expenses incurred by the Production Department in each year 2001 through 2006 (the test year). At line 8, a three-year average of 2004 through 2006 actual expenses is calculated and compared to HELCO proposed expense levels (at lines 9-11).

Q. HOW DID HELCO PREPARE ITS RATE CASE FORECAST OF MISCELLANEOUS PRODUCTION O&M MATERIALS?

A. The Company employed a series of spreadsheets of actual historical miscellaneous materials expense for prior years 1999 through 2004, computing either an average of such costs for the years 2001 through 2004 or for a shorter period that was subjectively selected for certain items, such as 2003 and 2004, utilizing either the calculated average, or a separately calculated input amount.[19] To these amounts, a 1.0424 escalation factor was applied to some of the calculated averages to estimate how costs may increase due to inflation "from 2004 to 2006 dollars."[20] Details of these calculations can be observed in the Company's response to CA-IR-2 (HELCO T-5), Attachment 2A, at pages 9 through 24.

Q. WHY DID HELCO'S APPROACH NOT PRODUCE REASONABLE RESULTS?

A. It appears that HELCO's combination of judgmental selection of multi-year averages for some items, fewer year averages for others, discrete calculations for certain items and escalation rates yields a result that is not consistent with historical spending levels. Indeed, when questioned about these results for discrete unusual line items from the spreadsheets, HELCO responded in CA-IR-335 that listed, "[[I]tems a through h, j and k are considered an overstatement of materials cost and will be reversed as an adjustment." This is the conceded adjustment that appears at line 13 of Consumer Advocate

19 See responses to CA-IR-78a. and CA-IR-338a.

20 CA-IR-338, part b.

Schedule C-3, but it does not completely correct for the overstatement of materials costs in the Company's test year forecast.

Q. IN APPLYING YOUR PROPOSED THREE-YEAR AVERAGE TO MISCELLANEOUS MATERIALS, DID YOU RECOGNIZE THAT HELCO HAS ALREADY CONCEDED A NEED TO CORRECT FOR OVERSTATEMENT OF SUCH EXPENSES?

A. Yes. Line 10 of Schedule C-5 reflects the amount by which HELCO has already conceded overstatement of miscellaneous materials costs (as noted in the response to CA-IR-447 and at line 13 of CA Schedule C-3).

Q. IS THERE ANY OBVIOUS TREND IN MISCELLANEOUS MATERIALS EXPENSES THAT SUPPORT HELCO'S APPLICATION OF AN ESCALATION FACTOR TO HISTORICAL AMOUNTS USED TO PREPARE TEST YEAR PROJECTIONS?

A. No. The actual 2006 test year expenses for miscellaneous materials were lower than actual expenses in 2004, the first year of the three-year averaging period that I have employed, but were higher than in other years. By including the peak spending year of 2004 in the average and not reaching back more than three years, I have calculated an average expense level that exceeds every historical year other than 2004, to the benefit of HELCO.

Q. AT SCHEDULE C-6, ANOTHER PRODUCTION O&M ADJUSTMENT IS PROPOSED TO REDUCE ESTIMATED OVERHAUL COSTS INCLUDED BY HELCO IN TEST YEAR EXPENSES. WHAT EXPENSES ARE THE SUBJECT OF THIS ADJUSTMENT?

A. HELCO prepared its rate case forecast based upon expected 2006 generating unit overhaul activity, but then proposed a series of normalizing adjustments to recognize that the level of such activity in a single year may not be representative of normal, ongoing conditions. At page 58 of HELCO T-5, Mr. Giovanni explains the "basis for other production maintenance non-labor normalization" adjustments totaling $289,000 as the net impact of a list of ten discrete generating unit maintenance projects.

Several of these listed adjustments relate to distant future low pressure turbine ("LPT") replacement projects that are designated, "Puna CT-3 LP Turbine Replacement," "CT-4 LP Turbine Replacement" and "CT-5 LP Turbine Replacemen.t" At page 59, Mr. Giovanni explains these adjustments as, "CT-3, CT-4 and CT-5 LP Turbine replacements will be performed every 10 years at an average cost of $650,000 each." Thus, the $65,000 added to expense (for each of the three units) is for each unit's assumed future LP turbine overhaul, based upon an estimated cost of $650,000, divided by an assumed 10-year replacement interval for each unit. The Consumer Advocate does not accept these adjustments because the costs being projected are highly speculative in amount, have not occurred historically and are not expected to be incurred in the near future.

Q. HAS HELCO EVER REPLACED A LOW PRESSURE TURBINE ON PUNA CT-3 SINCE THAT UNIT COMMENCED COMMERCIAL OPERATION IN 1992?

A. According to the response to CA-IR-258, "[t]he CT-3 Low Pressure Turbine ("LPT") has never been permanently replaced with a rotable unit, but underwent extensive repairs in the 1994 through 1996 timeframe as a result of environmental conditions that exist at the Puna site due to the original installation of the High Pressure Turbine ("HPT") and LPT." This response describes the repair work that was done on CT-3 and explains that ten years later, "[t]he repaired power turbine continues to function satisfactorily with 45,500 hours accumulated as of September 1, 2006, since being installed in October of 1996. CT-4 and CT-5 have accumulated runtime hours of only 10,528 and 8,680, respectively, as of August 6, 2006, and are not expected to reach 50,000 hours until 2013 or later.[21]

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[21] See response to CA-IR-258, Attachment 5.

Q. DOES THE MAJOR REPAIR WORK THAT WAS DONE ON PUNA CT-3 OVER TEN YEARS INDICATE A CLEAR NEED FOR THE SAME TYPE OF WORK NOW ON CT-3 OR IN THE IMMEDIATE FUTURE ON CT-4 OR CT-5?

A. No. According to the same response, "CT-4 and CT-5 were supplied with the proper platinum aluminide coatings on the HPT and LPT." This response also states that:

> Support for CT-3, CT-4 and CT-5 LP Turbines every 10 years at an average cost of $650,000 each is based on the manufacturer's recommendation to overhaul the LPT at 50,000 operating hour intervals on a condition based maintenance interval, in conjunction with a combustion turbine major overhaul. This is not a hard, fixed maintenance interval, but condition based. CT-3 is approaching this level of operating hours after 10 years (since October 1996). It is anticipated that CT-4 and CT-5, operating an average of 4600 hours per year currently, and expected to increase in annual operating hours once the combined cycle heat recovery units are built, to reach the 50,000 hour threshold in the 2012 and 2013 timeframe.

Thus, it appears that HELCO has included expenses in the 2006 test year for "condition based" LPT replacement work that may possibly be required, after runtime hours accumulate on the CT's, up to seven years in the future.

Q. REGARDING THE ASSUMED 50,000 HOUR ASSUMED LPT REPLACEMENT THRESHOLD, HAS THE COMPANY PROVIDED INCONSISTENT DATA REGARDING HOW OFTEN THIS WORK IS ACTUALLY REQUIRED?

A. Yes. In response to CA-IR-56, Attachment 1, the "Normal Outage Interval" for Puna CT-3, Keahole CT-4 and Keahole CT-5 is stated as, "LPT every 100,000 hours at a cost of $900K," not the 50,000 hour interval with costs at $650,000.

Q. WHAT IS THE APPARENT BASIS FOR THE 50,000 HOUR INTERVAL USED IN THE HELCO ADJUSTMENT TO THE 2006 FORECAST?

A. The response to CA-IR-258, Attachment 4 is an e-mail from General Electric ("GE") responding to inquiries from HELCO about this matter and the information provided indicates that HELCO's inquiries of GE were hypothetical, as suggested by the wide range of estimated costs provided in the e-mail and the statement by GE, "[s]ome discount is typically given off of list. I'd want to understand more about when you're thinking about doing the work before committing to a discount level." With regard to the assumed 50,000 hour interval, GE stated, "[t]ypically PT overhauls are performed at 50,000 hours. The PT, along with the rest of the GT, is serviced 'on-condition.' Some sites have been able to stretch longer than 50,000 hours. It really depends on what your borescope is telling you."

Q. SHOULD HELCO BE ALLOWED TO CHARGE ITS CUSTOMERS TO BEGIN COLLECTING FOR DISTANT FUTURE LPT TURBINE REPLACEMENT EXPENSES AT THIS TIME?

A. No. The Company's adjustment for this LPT replacement work is highly speculative, based upon; a) conjecture about what conditions may exist at future overhaul dates at these units; b) whether those conditions may (or may not) require LPT replacement many years from now, and; c) what LPT replacement work might then cost. In contrast to such speculation, many other discrete generating unit overhaul projects have been estimated and/or adjusted by HELCO that represent known periodic activities required each year, as illustrated in the discussion and "Reason" column at HELCO-WP-510, page 8, where other test year adjustments are described. The Consumer Advocate has accepted these other adjustments where they appear to be consistent with ongoing activities that occur with regular frequency and for which costs can be reasonably estimated.[22]

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22 In response to CA-SIR-7, the Company provided updated comparisons of prior years' actual overhaul cost data to test year "normalized" estimates. This information shows the correlation of test year projected spending to actual historical costs for periodic overhauls that have occurred or are projected to occur.

Q. IS THE ADJUSTMENT YOU PROPOSE CONSERVATIVELY GENEROUS TO HELCO, IN ALLOWING SOME COSTS FOR POTENTIAL LONG TERM LPT REPLACEMENT AND OTHER ACTIVITIES WHERE SPENDING HAS NOT OCCURRED HISTORICALLY?

A. Yes. Given the historical spending history at Puna CT-3 over ten years ago and the existence of more run time hours at that unit, I have accepted HELCO's proposed funding for some LPT work, even though that activity is not presently scheduled and may not be required in the immediate future. Additionally, even though HELCO has not historically overhauled any of the disbursed generation diesel units, I have allowed for such overhaul work at the revised levels requested by the Company.[23]

VII. <u>CUSTOMER ACCOUNTS EXPENSE</u>.

Q. DOES THE CONSUMER ADVOCATE DISPUTE ANY OF THE COMPANY'S PROJECTED TEST YEAR EXPENSES FOR THE CUSTOMER ACCOUNTS EXPENSE BLOCK CONTAINING NARUC ACCOUNTS 901 THROUGH 904?

A. No. The analyses we performed and additional information produced in response to information requests support approval of the Company's estimated Customer Accounts expenses.

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[23] CA-IR-259.

Q. At HELCO-705, PAGE 4, MR. FUJIOKA SPONSORS A CALCULATION OF UNCOLLECTIBLE ACCOUNTS EXPENSE AT PRESENT AND PROPOSED RATES. HAVE YOU ACCEPTED HIS PROPOSED UNCOLLECTIBLE FACTOR OF 0.12 PERCENT OF REVENUES?

A. Yes. This value has been accepted and is used in Exhibit CA-101, Schedule A-1, Line 7, to calculate a "Revenue Conversion Factor" recognizing incremental effects of changes in revenue levels, such as revenue taxes, uncollectibles and late payment revenues.

VIII. CUSTOMER SERVICE EXPENSES.

Q. WHAT TYPES OF EXPENSES ARE INCURRED BY HELCO THAT ARE CHARGED TO CUSTOMER SERVICE EXPENSE ACCOUNTS?

A. Customer Service expenses include the labor and non-labor costs incurred by HELCO to engage in and administer integrated resource planning ("IRP") and demand-side management ("DSM") activities, to develop and distribute information to customers and to interact with customers regarding energy rates and rate options, evaluation of energy efficiency and load management opportunities, energy safety, renewables and other energy-related topics of interest to the public.

Q. WHAT AMOUNT OF TEST YEAR EXPENSE IS PROPOSED FOR CUSTOMER SERVICES ACTIVITIES?

A. HELCO witness Mr. Beck (HELCO T-8) recommends a test year estimate for customer service expense of $2,252,000, as set forth in HELCO-801. This estimate is made up of $762,000 of proposed labor expense and $1,489,000 of proposed non-labor expense. These amounts are net of certain ratemaking adjustments to the Company's 2006 Operating Budget, including a reduction of $1,410,000 to remove incremental direct costs associated with DSM programs that are separately recoverable through the IRP surcharge tariff and a $500,000 expense increase adjustment for a proposed new Renewable Energy and Energy Efficiency Program for Affordable Homes (REEEPAH) program.[24]

Q. IN THE REVIEW OF TEST YEAR CUSTOMER SERVICE EXPENSES THAT WAS CONDUCTED BY THE CONSUMER ADVOCATE, DID YOU FIND THE COMPANY'S PROPOSED EXPENSE LEVEL TO BE REASONABLE?

A. I have reviewed the activities and projected costs for HELCO Customer Service personnel and agree with the majority of the estimated cost elements. With respect to labor expense, the Company added costs for a new "Customer Account Manager" position, but reduced the costs for this new position by half to recognize that the position was not filled for the entire year. In fact, this new

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24 See HELCO-WP-801 at pages 7-11 for adjustment details.

position was not filled until September 27, 2006.[25] The Consumer Advocate proposes no adjustment to the net proposed labor expenses, since HELCO has not proposed annualization of the new position as if it were filled throughout the test period. However, certain non-labor cost adjustments to HELCO's proposed test year Customer Service expenses are needed, as described below.

A. DEMAND SIDE MANAGEMENT ("DSM") EXPENSES.

Q. HOW DID HELCO TREAT DSM EXPENSES IN PREPARING ITS RATE CASE FILING?

A. HELCO'S rate case filing is based upon a forecast of 2006 expenses that included two types of DSM expenditures; those that are incremental direct program expenses for Commission-approved DSM programs and those that are indirect expenses for labor needed to administer DSM programs. Because this first category of expenses is recoverable through the IRP surcharge, a ratemaking adjustment is required and has been made by HELCO to remove these expenses from the base rate revenue requirement. According to HELCO witness T-8 at page 18, "[f]or the 2006 test year, the adjustments remove the 2006 DSM incremental expense estimates of $1,410,000."

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[25] CA-IR-355.

Q. WHAT CRITERIA ARE USED BY HELCO TO ISOLATE DSM COSTS THAT ARE RECOVERED THROUGH THE IRP SURCHARGE, RATHER THAN THROUGH BASE RATES?

A. Mr. Curtis Beck explains how the Company categorizes its DSM program costs that are eligible for recovery through the IRP surcharge mechanism, indicating at page 21 the definitions that are employed by the Company. One category of customer service expenses are the costs referred to as "program" expenses that HELCO tracks and bills to customers through the IRP surcharge, based upon the following definition:

> DSM program expenses are defined by HELCO as those costs incurred specifically by activities that directly result in, and are explicitly for the purpose of, implementation of its four full-scale DSM programs.

In addition to the so-called "program" expenses, HELCO also categorizes certain other costs related to DSM activity as "non-program" costs for which base rate recovery is proposed. These expenses are described at T-8, page 21 as:

> DSM program expenses that are recovered through base rates include only HELCO employee labor costs that were specifically identified in HELCO's last rate case as DSM activities and allowed by the Commission in the test year 2000 expenses for ratemaking purposes.

Because of this distinction, the Company has proposed a ratemaking adjustment to remove only the projected test year expenses falling within the first category that are surcharge recoverable, while including the second category of expenses for base rate recovery.

Q. DOES THE CONSUMER ADVOCATE AGREE THAT THIS ACCOUNTING DISTINCTION SHOULD BE CONTINUED IN DETERMINING HELCO'S REVENUE REQUIREMENT?

A. No. The Consumer Advocate supports changing this accounting distinction, so that prospectively all DSM activities and expenses, including incremental program expenditures as well as indirect labor costs to administer DSM programs, are fully recovered through the IRP surcharge mechanism. This change will enable future adjustments to HELCO's involvement in DSM with tariff tracking of all cost changes associated with such adjustments.

Q. DID THE COMMISSION RECENTLY ADDRESS HOW DSM COSTS INCURRED BY THE HECO COMPANIES ARE TO BE RECOVERED?

A. Yes. In Decision and Order No. 23258, issued in Docket No. 05-0069, the Commission ordered that:

> All of the HECO Companies' Energy Efficiency DSM programs shall transition from the HECO Companies to the Non-Utility Market Structure, by January 2009, unless otherwise ordered by the commission. The HECO Companies' Load Management programs shall be excluded from the third-party administrator's area of responsibility.[26]

That Order also provides that:

> Under the Utility Market Structure, the Existing Cost Recovery Mechanism shall continue to apply, such that labor costs shall

[26] Decision and Order No. 23258, page 144, Ordering Paragraph No. 4.

> be recovered through base rates and all other DSM-related utility-incurred costs shall be recovered through a surcharge.[27]

Q. DOES THE CONTINUATION OF EXISTING COST RECOVERY FOR DSM LABOR COSTS THROUGH BASE RATES, UNTIL THE TRANSITION TO A NON-UTILITY MARKET STRUCTURE IS COMPLETED, CREATE ANY PROBLEMS WITH REGARD TO UTILITY RATEMAKING?

A. Yes. When responsibility for DSM program administration is transferred from the utility to other parties, there is no ability to remove utility DSM labor costs that are avoided by the utilities from base utility rates in the absence of a utility rate case that occurs coincident with such transfer. Absent a timely rate case, the utility will continue to collect DSM labor costs in its rates at the same time the newly incurred labor costs of the third party provider will become chargeable to ratepayers.

Q. HOW MIGHT THIS PROBLEM BE ADDRESSED?

A. I recommend certain changes be implemented as part of DSM accounting in the current round of HECO Company rate cases. Specifically, the rate case estimated labor costs for DSM administration should be isolated and added to the surcharge recovery mechanism starting with the effective date of new base rates. Then, when the transition to the non-utility market structure is completed, it will be possible to discontinue ratepayer funding of utility labor

27 Id, Ordering Paragraph No. 6.

costs to administer DSM programs. While this approach is not entirely consistent with the Commission's findings in Decision and Order No. 23258 regarding the intended continuation of base rate recovery of DSM labor, it is the only way that double recovery of future labor costs can be avoided.

Q. IS ANOTHER RATEMAKING ADJUSTMENT REQUIRED TO SHIFT THE TEST YEAR INDIRECT LABOR COSTS TO ADMINISTER DSM PROGRAMS FROM BASE RATE RECOVERY TO IRP CLAUSE RECOVERY?

A. At CA Schedule C-9, a separate adjustment is made to isolate the labor costs projected for test year administration of DSM programs. This is not a disallowance of these expenses, but rather a proposed reclassification of expense for IRP clause recovery commencing with the effective date of new base rates in this Docket. Effective with the implementation of new base rates in this Docket, HELCO would commence adding $168,000 annually to its surcharge recoverable DSM costs and this amount would continue to be added until transition to Non-Utility DSM provisioning is completed.

B. RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAM FOR AFFORDABLE HOMES (REEEPAH).

Q. WHAT IS THE RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAM FOR AFFORDABLE HOMES THAT IS PROPOSED BY HELCO?

A. This is a new program that HELCO is proposing for implementation, for which rate case proposed expenses have been increased by $500,000 to provide initial funding. This new proposal is described by Mr. Beck at T-8, starting at page 6 with the statement,

> REEEPAH is planned for implementation in 2006 with the program budget included in the 2006 Budget. The purpose of this program is to provide lower income residential customers with more options to manage their electricity bills, which have increased over the past two years. Two of the options under consideration within this program are 1) a residential solar water heater grant program; and 2) a customer assistance program that provides photovoltaic system installation in affordable housing developments and consultation to customers wishing to participate in HELCO's net energy metering program. Other programs, such as buying down the cost of solar water heating systems that would be leased to homeowners, are under consideration as well.

This new program, if approved by the Commission, would help to mitigate the financial impacts of high electricity prices and further increases in electricity bills to residential ratepayers. The REEEPAH would be targeted to indirectly assist low to moderate income residential customers who are struggling to deal with the affordable housing challenges on the Big Island by providing developers of affordable housing with financial incentives to install solar photovoltaic and solar water heating systems.[28]

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[28] HELCO responses to CA-IR-106 and CA-IR-241. In its response to CA-IR-242, HELCO offered additional information about its vision of REEEPAH, including a draft of a solar water heating grant program at pages 3-7.

Q. IF THE REEEPAH PROGRAMS INVOLVE ENERGY EFFICIENCY INCENTIVE PAYMENTS, WHY ARE THEY NOT SIMPLY OFFERED AS MODIFICATIONS OF HELCO DEMAND SIDE MANAGEMENT PROGRAMS?

A. According to HELCO's response to CA-IR-241:

> Providing assistance to developers of affordable housing projects to incorporate renewable energy facilities, particularly solar photovoltaic systems, within the affordable housing communities, is an element of REEEPAH which cannot be provided within the context of DSM energy efficiency programs. Also, providing assistance to developers of affordable housing projects to incorporate energy efficiency measures, particularly solar water heating systems, specifically within the affordable housing communities and at assistance levels that exceed the incentive co-payments of the existing REWH program, is an element of REEEPAH which cannot be provided within the context of DSM energy efficiency programs.

Thus HELCO envisions REEEPAH programs to exist and be funded separately, to supplement and expand upon the Company's Commission approved DSM programs. The same CA-IR-241 response explains:

> Renewable energy facilities cannot be provided within the context of the DSM energy efficiency programs that are offered, or are proposed to be offered by the Company, because renewable energy facilities do not fall within the definition of DSM energy efficiency programs. The energy efficiency programs that will be included in REEEPAH will not preclude affordable home customers from participating in the DSM energy efficiency programs that are offered, or are proposed to be offered by the Company. Rather, affordable home customers will be able to participate in both REEEPAH and HELCO's DSM energy efficiency programs that are offered, or are proposed to be offered by the Company.

Q. ENERGY EFFICIENCY DSM PROGRAMS ARE ROUTINELY EVALUATED BY REGULATORS TO DETERMINE THEIR EFFECTIVENESS IN RELATION TO COSTS, USING VARIOUS UTILITY COST, TOTAL RESOURCE COST, RATEPAYER IMPACT OR OTHER METRICS. HAS HELCO PREPARED ANALYSES OF ITS NEWLY PROPOSED REEEPAH PROGRAMS USING THESE TYPES OF EVALUATION TOOLS?

A. No. In its response to CA-IR-106, HELCO stated:

> No reports, studies, analyses, workpapers or projections were specifically prepared for the proposed REEEPAH. The purpose of the program is to provide lower income residential customers, which have increased over the past two years, with more 'built-in' options to manage their electricity bills. The need for the program emerged after a review of HELCO's current residential rate structure (see HELCO T-19) demonstrated the need for innovative approaches to mitigate the financial impacts of further increases in electricity bills to residential ratepayers.

After providing more details about its interaction with the County of Hawaii regarding the affordable housing project at Waikoloa, this IR response concludes:

> HELCO proposes the annual $500,000 expenses for REEEPAH because this amount will allow HELCO to pursue energy efficiency and renewable technologies in a manner that is financially significant for affordable housing projects but at a level that is relatively small from a rate impact perspective.

Q. DID THE CONSUMER ADVOCATE ASK HELCO FOR ADDITIONAL EVIDENCE OF THE COST EFFECTIVENESS OF THE NEW REEEPAH

PROPOSAL, AFTER BEING TOLD THE COMPANY HAD PREPARED NO STUDIES OR REPORTS?

A. Yes. In CA-IR-267, HELCO reiterated the goals of REEEPAH and provided a study done by Global Energy Partners that is assisting HELCO in the development of REEEPAH. From that study, HELCO concluded that

> ...there exist substantial market and economic barriers to expanding the rate of solar water heating installations beyond those levels in HELCO's new DSM programs already being developed in IRP-3. About the same time...HELCO was becoming acutely aware of a key socio-economic issue in Hawaii County, namely the problem of affordable housing. Further, at the urging of the Mayor of Hawaii County, HELCO had entered into discussions with the County regarding the possibility of forming a partnership to utilize energy efficiency and renewable energy technologies to support affordable housing strategies and goals.

That response also stated:

> Currently, HELCO is working with its consultant Global Energy Partners to draft a REEEPAH framework, and expects that this will be ready in time for HELCO's rebuttal testimony in this rate case. HELCO is open to working with the Consumer Advocate to develop the REEEPAH into a workable program.

Q. WHAT IS THE CONSUMER ADVOCATE'S RESPONSE TO THE PROPOSED REEEPAH AND HELCO'S OFFER TO "WORK WITH THE CONSUMER ADVOCATE TO DEVELOP REEEPAH INTO A WORKABLE PROGRAM"?

A. The Consumer Advocate believes that energy efficiency programs and any new subsidies for renewable energy installations need to be subjected to rigorous cost/benefit analysis <u>before</u> ratepayer funding is committed to such efforts. Moreover, the use of utility revenues to fund programs designed to subsidize the cost of affordable housing raises regulatory policy concerns that may be beyond the scope of a rate case. In the instance of REEEPAH, a need for affordable housing on the Big Island is clearly complicated by high prices for electricity that are compounded by base rate increases and ECAC charges reflecting high fuel prices. The Consumer Advocate has supported a creative rate design response to this problem in the form of inclining block residential rates for residential customers.[29] However, rate case advance funding for a conceptual program such as REEEPAH, for which no details are now finalized, is inappropriate. Moreover, as noted above in the discussion of DSM cost recovery, HELCO's future involvement in energy efficiency program provisioning is scheduled to change as a result of Decision and Order No. 23258 that was recently issued by the Commission the Energy Efficiency Docket No. 05-0069.

Q. PLEASE EXPLAIN THE ADJUSTMENT SET FORTH AT CA ADJUSTMENT SCHEDULE C-10.

A. This adjustment eliminates HELCO's proposed new funding for the REEEPAH program. The Consumer Advocate does not support initiation of new energy efficiency programs, even those targeted to affordable homes energy

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29 See CA T-5 at pages 44-49.

efficiency, in light of the future Non-utility Market Structure for demand side management activity that was recently implemented by the. The REEEPAH would appear to expand upon energy efficiency programs within the existing Utility Market Structure at a time when the Commission has ordered "[a]ll of the HECO Companies' Energy Efficiency DSM Programs shall transition from the HECO Companies to the Non-Utility Market Structure, by January 2009."[30]

Q. WHAT SHOULD BE DONE WITH THE NEW TARIFF SPONSORED BY MR. YOUNG (HELCO T-20), AT PAGES 50 THROUGH 52, TO TRACK AND RECONCILE SPENDING ON REEEPAH?

A. This tariff is not needed and should be rejected, along with the advance *funding for the REEEPAH program at this time.*

C. CUSTOMER SERVICE PROJECTS.

Q. WHAT IS THE PURPOSE FOR CONSUMER ADVOCATE ADJUSTMENT SCHEDULE C-11?

A. This adjustment reduces the costs for several Customer Service Department outside service items to more reasonable ongoing cost levels. The cost amount set forth at line 1 reflects an updated cost estimate for intercompany charges from HECO to support Combined Heat and Power project development efforts. In its responses to CA-IR-354, 447 and 460, the

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30 Decision and Order No. 23258, Docket No. 05-0069, page 144.

Company conceded the need to reduce these estimated charges by $29,192, an amount that is accepted by the Consumer Advocate at line 3. The remaining adjustment at line 8 reduces HELCO's estimated customer service project costs totaling $93,177 in total test year expenses, for which actual year-to-date expenditures through October 2006 were only $21,704. The adjustment proposed by the Consumer Advocate for these projects is to assume continued spending in the last two months of 2006 at the same level as actual expenditures in the first 10 months, which when added to the $21,704 actually spent, supports a downward adjustment of $67,000.

IX. <u>INCOME AND OTHER TAXES</u>.

Q. WHAT TYPES OF TAXES ARE INCLUDED IN THE COMPANY'S ASSERTED REVENUE REQUIREMENT?

A. The Company's filing includes three types of taxes. Certain revenue taxes are paid based upon the amount of taxable revenues collected by HELCO. These include the Public Service Company ("PSC") tax, the State Public Utility ("PUC") fee, and the County Franchise Royalty tax. Payroll taxes that include Federal Insurance Contribution Act and Medicare ("FICA/Medicare"), Federal Unemployment Taxes ("FUTA") and State Unemployment Act ("SUTA") taxes are also paid by HELCO and included in the revenue requirement. Revenue and payroll-based taxes are generally referred to as "taxes other than income taxes" and are summarized at test year levels in HELCO-1301. Finally, HELCO must pay Federal and State income taxes on its taxable income and the test year expense for these taxes is calculated at HELCO-1302.

Q. WITH RESPECT TO REVENUE TAXES, DOES THE CONSUMER ADVOCATE TAKE EXCEPTION TO THE COMPANY'S CALCULATIONS OF TEST YEAR EXPENSE?

A. Yes. The Company failed to properly account for the bad debt deduction available to it when calculating the tax liability for the PSC tax and for the PUC fee. Hawaii Revised Statutes ("HRS") §239-2 provides the definition of gross income from public service company business and "[a]ccounts found to be worthless and actually charged off for income tax purposes...may be deducted from gross income" under this definition. A similar deduction is allowed in calculating the PUC fee. Consumer Advocate Adjustment Schedule C-13 has been prepared to quantify the reduction to these revenue taxes to account for test year levels of bad debt expense at present rates. In its response to CA-IR-285, HELCO conceded that this correcting adjustment should be made.

Q. WITH RESPECT TO PAYROLL TAXES, HAS THE CONSUMER ADVOCATE DETERMINED THAT ANY ADJUSTMENT IS REQUIRED TO THE AMOUNTS SET FORTH ON HELCO-1301?

A. Yes. HELCO-WP-1301 at page 3 indicates that test year payroll taxes were calculated based upon the assumption that the year-end number of employees would be 376 and that gross pay subject to FICA and Medicare taxes would be commensurate with this increased staffing level. However, actual wage costs and headcounts throughout the test year were much lower, as noted elsewhere in my testimony. Consumer Advocate Adjustment Schedule C-12 reflects a downward adjustment to test year payroll taxes to account for reduced labor cost levels actually incurred by HELCO in the test year.

Q. PLEASE EXPLAIN HOW THE CONSUMER ADVOCATE'S ADJUSTMENT TO PAYROLL TAXES HAS BEEN QUANTIFIED.

A. FICA and Medicare taxes are driven by taxable wage costs. Therefore, at lines 1 through 9 of Schedule C-12, a ratio is calculated comparing the Consumer Advocate's adjustment to HELCO's labor costs for the test year to the Company's proposed level of labor costs. This "reduction" ratio is then applied to the proposed level of FICA/Medicare taxes at line 10 to calculate an estimated adjustment reducing such taxes. With respect to FUTA and SUTA, the tax rates are applied to a very low per-employee wage base each year, so that the tax effectively becomes an annual tax on each employee. At lines 12 to 14 of Schedule C-12, the actual year-end HELCO employee count of 340 persons is compared to the 376 employee level used by HELCO to estimate the tax.[31] The resulting ratio is then applied to the Company's

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[31] See HELCO-WP-1301, page 3, lines 28 and 29.

proposed FUTA and SUTA tax expense levels to adjust these expenses in conformance with the Consumer Advocate's labor cost adjustments.

Q. HOW DID THE COMPANY CALCULATE TEST YEAR INCOME TAXES?

A. The Company's income tax expense calculation appears at HELCO-1302 and is based upon a "short-form" approach, in which overall income tax is calculated using a composite Federal/State income tax rate without distinguishing between currently payable taxes and accruals of deferred income taxes that arise from book/tax timing differences. This "short-form" approach is described by Ms. Ishii at pages 5 through 9 of HELCO T-13. The calculation produces reasonable results for the test year by reflecting all ratemaking adjustments made to taxable revenues and expenses and by including an amount of deductible interest that is reasonably close to interest costs implied by the weighted cost of debt capital applied to rate base for the test year. However, the Company has failed to account for the tax savings created by the American Jobs Creation Act in its Direct Testimony, even though definitive guidance now exists to quantify the IRC Section 199 tax deductions that were created by the Act.

Q. WHAT IS THE PURPOSE OF CONSUMER ADVOCATE SCHEDULE C-20?

A. This Schedule quantifies an adjustment to income taxes based upon the test year estimated benefit available to HELCO as a result of IRC Section 199.

The adjustment is based upon a Company-prepared estimate of its "estimated taxable income for generation activity" at HELCO-proposed rate levels, with further adjustment for the somewhat lower return recommended on production rate base assets by the Consumer Advocate (see Schedule D) and for the statutory six percent deduction value effective on January 1, 2007.

Q. HAS HELCO CONCEDED, IN RESPONDING TO CONSUMER ADVOCATE INFORMATION REQUESTS, THAT IT SHOULD NOW ACCOUNT FOR AND RECOGNIZE THE NEW TAX DEDUCTION AVAILABLE TO IT UNDER SECTION 199 OF THE INTERNAL REVENUE CODE?

A. Yes. In its responses to CA-IR-469 and CA-SIR-23, the Company acknowledged that it has qualifying production activity income that qualifies for the new deduction. Calculations of the estimated tax deduction arising from Section 199, based upon the Company's allocated test year cost of service, were provided in the CA-SIR-23 response.

Q. PLEASE DESCRIBE THE NEW TAX DEDUCTION AVAILABLE TO ELECTRIC UTILITIES PURSUANT TO IRC SECTION 199.

A. Starting with tax year 2005, a business may take a new deduction based upon a statutory percentage of its "qualified production activity income" ("QPAI"). Under section 199, the allowed deduction is equal to a percentage of the lesser of (a) income derived from qualified production activities for the taxable year ("QPAI") or (b) taxable income. The deduction percentage is three percent in 2005 and 2006, six percent in 2007-2009 and nine percent in 2010 when the deduction is fully phased in and is limited to 50 percent of W-2 Wages (as defined) paid during the calendar year ending during the taxpayer's taxable year.

QPAI is calculated by subtracting from domestic production gross receipts ("DPGR") for the taxable year: (1) cost of goods sold ("CGS") that are allocable to such receipts, (2) other deductions directly allocable to such receipts and (3) a ratable portion of other deductions. DPGR include gross receipts derived from any lease, rental, sale, exchange or other disposition of (a) qualifying production property ("QPP") (tangible personal property, computer software and sound recordings) which was manufactured, produced, grown or extracted ("MPGE") by the taxpayer in whole or in significant part within the U.S. and includes electricity, natural gas or potable water produced by the taxpayer in the U.S.[32]

[32] IRC Section 199(a)(b)(c).

Q. WHY DID YOU NOT RECOGNIZE THE INCREASED SIX PERCENT DEDUCTION VALUE EFFECTIVE IN 2007 FOR USE IN THIS DOCKET, GIVEN THAT THE INCREASED PERCENTAGE IS EFFECTIVE IMMEDIATELY AFTER THE TEST YEAR?

A. The Consumer Advocate has limited the Section 199 deduction to the lower 2006 statutory percentage value of 3 percent, recognizing that the deduction will be understated by half in relation to the tax savings HELCO will enjoy when new rates are effective later in 2007, in the interest of maintaining consistency with the average 2006 test year used to quantify the revenue requirement. In the event HELCO argues for recovery of any post test year cost increases or for annualization of any increasing expense, the Commission should double the Section 199 tax deduction and savings to recognize this increasing benefit to the Company starting on January 1, 2007.

X. DEFERRED TAX RESERVES IN RATE BASE.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT SCHEDULE B-3?

A. This adjustment updates and corrects the Company's test year estimates of Accumulated Deferred Income Taxes ("ADIT"), as set forth in HELCO-1305, and then further adjusts such amounts to exclude certain items not properly reflected within rate base.

Q. WHY IS IT NECESSARY TO UPDATE AND CORRECT THE ADIT RESERVE BALANCES?

A. A more accurate revised quantification of this rate base element is now possible. In responding to Consumer Advocate Information Requests, HELCO provided updated estimates of the preliminary year-end 2006 per book reserve balances that are available to replace estimated amounts. In addition, HELCO indicated a need to correct and revise the individual components of ADIT for several corrections and to remove amounts improperly included in the ADIT balance in the Company's Direct Testimony.

Q. PLEASE DESCRIBE THE ADJUSTMENT CALCULATED AT LINES 1 THROUGH 4 OF SCHEDULE B-3.

A. In its response to CA-SIR-18, HELCO responded to a request for actual per books ADIT amounts by providing updated ADIT amounts based upon preliminary data "...because the financial statements have not been finalized as of the date of this submission." The preliminary actual per-book values are used to quantify an adjustment to update the test year deferred tax estimates. Included within this update is an adjustment to exclude certain debit ADIT balances associated with a Keahole Settlement accrual that HELCO concedes should not be included in rate base.[33] The Keahole Settlement ADIT amounts exist because the Company accrued approximately $3 million in book

33 See CA-IR-173, CA-IR-176, page 3 and CA-SIR-18, page 4 at "Keahole Settlement".

expenses related to the Keahole Settlement Agreement in 2003, but for tax purposes these settlement costs are deductible when paid.[34]

Q. PLEASE EXPLAIN THE ITEMS LISTED AS "CONCEDED ADJUSTMENTS TO CORRECT DEFERRED TAXES" AT LINES 5 THROUGH 16 OF CA SCHEDULE B-3.

A. In its response to a series of information requests, as identified in the "reference" column of Schedule B-3, HELCO has quantified several true-up adjustments, reclassifications and items that should be excluded from the ADIT balance reflected in rate base. These adjustments are understood to be supported by HELCO and are necessary to more accurately quantify ADIT balances for the test year. At line 6, notation is made for the Keahole Settlement elimination that was already captured within the Company's updated ADIT balances in line 2. The "true-up" adjustment at line 7 is to correct the recorded year-end 2005 ADIT balances for adjustments booked late in 2006 upon finalization of the 2005 Federal Income Tax return.[35] A needed reclassification of ADIT amounts to exclude deferred tax items associated with Supplemental Non-qualified Pension and Executive Life Insurance is set forth at line 8.[36] The other ADIT items at lines 9 through 15

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34 CA-IR-173, page 4.

35 CA-IR-447, page 2 summary items 11 and 12; and pages 4 and 5.

36 CA-IR-447, page 2 summary items 5 and 6; and page 6.

represent deferred taxes for timing differences either improperly recorded on HELCO books or that should not be included in rate base because the corresponding transactions are not reflected in rate base, as more fully described in the referenced paragraphs of the Company's response to CA-R-280.

Q. WHAT ARE THE REMAINING ADIT ADJUSTMENTS THAT ARE LISTED AT LINES 17 THROUGH 24 OF CA SCHEDULE B-3?

A. These adjustments represent CA-proposed exclusion items beyond those already conceded by HELCO. For example, at line 18, I have removed the debit ADIT balances associated with accrual accounting on HELCO books for bad debt expenses, because electric rates are set for HELCO based upon the ratio of bad debt write-offs to revenues[37] (rather than accrual entries) and because the bad debt reserve balance is not recognized as a reduction to rate base. If the book bad debt reserve balance is not treated as a rate base credit, then the related debit ADIT balance should also not be included in rate base.

The next three items relate to timing differences between the book and tax treatment of HELCO spending on certain DSM, IRP and energy services costs, versus surcharge recovery of such costs. For book purposes, these

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[37] See HELCO-WP-705, where "Adjusted Net Write-offs" are compared to "Sales Revenue" to calculate an "Adjusted Percent Write-off" of 0.12% for the test year.

costs are capitalized and expensed when the related revenues are collected.[38] Over and under-recoveried balances of deferred DSM and IRP costs are not included in rate base, so any related ADIT balances should also be excluded from rate base to maintain consistent treatment. Significant amounts of DSM program costs are recovered through the surcharge mechanism, through which over and under-recoveries are reconciled and interest is calculated on the over/under recovered balances.[39] It may be appropriate to consider reducing this interest provision to apply to only the net-of-income tax over/under recovered balance so as to recognize the tax deductibility of DSM expenditures, but there is no reasonable method to develop a normalized and representative ADIT balance for such activity in determining rate base. Therefore, the test year estimated ADIT balances for DSM/IRP related timing issues should not be included in rate base.

The last two ADIT items at lines 22 and 23 relate to the timing of tax recognition for interest earned on undrawn revenue bond funds and for costs associated with the early redemption of revenue bonds. HELCO has included these ADIT balances because of the belief that, "[t]he tax effect of interest expense is included in rate base as a component of working cash and correspondingly, the deferred tax asset should also included in rate base."[40]

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38 See CA-IR-280, parts n, j and u.

39 See CA-IR-471a. and CA-IR-280n.

40 CA-IR-280, parts d and o.

However, there is no rate base component of working cash for interest, so this assertion is illogical. The timing of interest-related cash flows is excluded from the Working Cash allowance.[41] Since the liability associated with accrued interest costs is not included in rate base, there should be no rate base inclusion of interest-related ADIT balances.

XI. UNAMORTIZED STATE ITC BALANCE.

Q. PLEASE EXPLAIN THE ADJUSTMENT AT CA SCHEDULE B-4.

A. This adjustment updates the test year estimate of deferred State Investment Tax Credits, based upon the Company's response to CA-SIR-18. A more accurate, updated estimate of the unamortized State ITC amount was developed at pages 7-44 of this response and is tied to current expectations regarding the completion of ITC-eligible costs incurred for qualifying test year construction projects.

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41 See HELCO-1606, where no line item for interest expense is included. If interest were included in the Working Cash study, rate base would be lower because of the arrears payment of interest.

Q. IS THERE A CORRESPONDING ADJUSTMENT TO UPDATE THE INCOME TAX EXPENSE ESTIMATE FOR 2006 AMORTIZATION OF DEFERRED STATE ITC?

A. No. The Company's response to CA-SIR-18 at page 7 indicates an estimated 2006 amortization of $501 (thousand), which is the same amount included in the Company's Direct filing at HELCO-1304, line 2 for Test Year 2006.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does. My additional Direct Testimony addressing cost of service and rate design issues is designated CA T-5.

MICHAEL L. BROSCH

Summary of Qualifications

EMPLOYER:	Utilitech, Inc. Regulatory and Management Consultants
POSITION:	President
ADDRESS:	740 NW Blue Parkway, Suite 204 Lee's Summit, Missouri 64086

PRIOR EXPERIENCE:

1978-1982	Missouri Public Service Commission, Senior Accountant
1982-1983	Troupe, Kehoe, Whiteaker & Kent CPA's, Regulatory Consultant
1983-1985	Lubow, McKay, Stevens and Lewis, Project Manager
1985-Present	Utilitech, Principal and President

DEGREES:
University of Missouri – Kansas City
Bachelor – Business Administration (Accounting 1978) "with distinction"

OTHER QUALIFICATIONS:
Certified Public Accountant – Certification in Kansas and Missouri

Member	American Institute of Certified Public Accountants Missouri Society of Certified Public Accountants Kansas Society of Certified Public Accountants Beta Alpha Psi, professional accounting scholastic fraternity
Seminars	Iowa State Regulatory Conference 1981, 1985 Regulated Industries Symposium 1979, 1980 Michigan State Regulatory Conference 1981 United States Telephone Association Round Table 1984 NARUC/NASUCA Annual Meeting 1988, Speaker NARUC/NASUCA Annual Meeting 2000, Speaker
Instructor	INFOCAST Ratemaking Courses Arizona Staff Training Hawaii Staff Training

PRIOR TESTIMONIES: (See listings attached)

Utility	Jurisdiction	Agency	Docket/Case Number	Represented	Year	Addressed
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base
United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes

Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues
UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public S2ervice Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest
Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaii Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income

US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply
Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting
ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting

U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Qwest Communications – Dex Sale	Utah	PSC	02-049-76 02-049-82 01-2383-01	Consumer Advocate	2003	Directory Publishing
Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base
Verizon Northwest	Washington	WUTC	UT-040788A	Attorney General	2004	Operating Income, Rate Base, Directory Imputation
Public Service Company of Oklahoma	Oklahoma	OCC	Cause No. 200300076	Attorney General	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Hawaiian Electric Company, Inc.	Hawaii	PUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counsel	2005	Operating Income, Debt Service, Ratemaking Policy, Working Capital
Puget Sound Energy	Washington	WUTC	UE-060266 et al	Attorney General	2006	Ratemaking Policy, Rate Trackers
Cascade Natural Gas	Washington	WUTC	UG-060256	Attorney General	2006	Ratemaking Policy, Rate Trackers
Arizona Public Service	Arizona	ACC	E-01345A-05-0816	Staff	2006	Operating Income, Cost of Service
Union Electric Company dba AmerenUE	Missouri	PSC	ER-2007-0002	Attorney General	2006	Operating Income, Rate Base, Affiliate Transactions

**HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
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AND SUPPORTING SCHEDULES**

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Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
CHANGE IN GROSS REVENUE REQUIREMENT
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	REFERENCE	HELCO PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Proposed Rate Base	(a)	$ 373,100	$ 347,139
2	Pro Forma Change in Working Cash	(a)	(3,965)	(2,204)
3	Rate Base at Proposed Rates		$ 369,136	$ 344,934
4	Rate of Return	(b)	8.65%	7.95%
5	Operating Income Required	Line 3 * Line 4	$ 31,930	$ 27,422
6	Net Operating Income Available	(c)	15,291	18,170
7	Operating Income Deficiency	Line 5 - Line 6	$ 16,640	$ 9,252
8	Revenue Conversion Factor	(d)	1.798771	1.798771
9	Revenue Deficiency (Excess)	Line 7 * Line 8	**$ 29,931** (e)	**$ 16,643**

Footnotes:

(a) Source: CA Schedule B.
(b) Source: CA Schedule D.
(c) Source: CA Schedule C.
(d) Source: CA Schedule A-1.
(e) Source: HELCO-2101 & HELCO-WP-2101.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
REVENUE CONVERSION FACTOR
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	RATES	HELCO PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)	(E)
1	Gross Electric Sales Revenue			99.83003%	99.83003%
2	Add: Other Operating Revenue	(a)	See footnote	0.16997%	0.16997%
3	Total Operating Revenue	Line 1 + 2		100.00000%	100.00000%
4	Less: Franchise Royalty Tax	(b)	2.500%	-2.49276%	-2.49276%
5	Less: Public Service Company Tax	(b)	5.885%	-5.88500%	-5.88500%
6	Less: Public Utility Commission Fees	(b)	0.500%	-0.50000%	-0.50000%
7	Less: Uncollectibles	(d)	0.120%	-0.12000%	-0.12000%
8	Net Revenue (before income taxes)	Lines 3..7		91.00224%	91.00224%
9	Less: Effective State Income Tax	(b)	6.0150%	-5.47378%	-5.47378%
10	Less: Effective Federal Income Tax	(c)	35.0000%	-29.93496%	-29.93496%
11	Net Operating Earnings	Lines 8..10		55.59350%	55.59350%
12	Income to Revenue Multiplier	Line 1 / 11		1.7987715	1.7987715

Footnotes:

(a) Ratio of Forfeited Discount Other Revenues over Sales Revenues
See HELCO-2101 & Hbase.xls [$50,787 / $29,880,313 = 0.16997%].
(b) Revenue Tax Rates per HELCO-WP-1301 & HELCO-WP-2101.
(c) State Income Tax rate per HELCO-WP-1301 & HELCO-WP-2101, FIT rate is statutory.
(d) Uncollectible Factor per HELCO-705 & HELCO-WP-2101.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SUMMARY OF JURISDICTIONAL RATE BASE
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	HELCO PRO FORMA TEST YEAR	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
	Investments in Assets Serving Customers			
1	Net Cost of Plant in Service	$ 458,657	$ (21,169)	$ 437,488
2	Property Held for Future Use	65	-	65
3	Fuel Inventory	8,266	(1,105)	7,161
4	Materials & Supplies Inventory	3,121	-	3,121
5	Unamortized Net SFAS 109 Regulatory Asset	10,798	-	10,798
6	Prepaid Pension Asset	14,172	(29)	14,143
7	Unamortized OPEB Regulatory Asset	1,715	-	1,715
8	Total Investments in Assets	496,793	(22,303)	474,490
	Funds from Non-Investors			
9	Unamortized CIAC	(57,537)	(622)	(58,159)
10	Customer Advances	(28,926)	(1,591)	(30,517)
11	Customer Deposits	(931)	-	(931)
12	Accumulated Deferred Income Taxes	(24,972)	(1,376)	(26,348)
13	Unamortized ITC	(11,795)	(70)	(11,865)
14	OPEB Liability	(1,715)	-	(1,715)
15	Total Deductions	(125,875)	(3,659)	(129,534)
16	Difference	370,918	(25,962)	344,956
17	Working Cash at Present Rates	2,183	-	2,183
18	Rate Base at Present Rates	373,100	(25,962)	347,139
19	Change in Rate Base - Working Cash	(3,965)	1,760	(2,204)
20	Rate Base at Proposed Rates	$ 369,136	$ (24,202)	$ 344,934
		(a)		

Footnotes:

(a) Source: HELCO-WP-2101 .

(b) Incremental Working Cash for the Consumer Advocate's Revenue Requirement is derived by ratio adjustment of the Company's proposed value, as follows:

	Rate Increase	Work Cash	Ratio WC/Rates
Company Filing	29,931	(3,965)	-0.13245
Consumer Advocate	16,643	(2,204)	-0.13245

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SUMMARY OF RATE BASE ADJUSTMENTS
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Investments in Assets Serving Customers									
1	Net Cost of Plant in Service	$ 1,205	$ -	$ -	$ -	$ -	$ -	$ (13,405)	$ (8,969)	$ (21,169)
2	Property Held for Future Use	-	-	-	-	-	-	-	-	-
3	Fuel Inventory	-	-	-	-	(1,105)	-	-	-	(1,105)
4	Materials & Supplies Inventory	-	-	-	-	-	-	-	-	-
5	Unamortized Net SFAS 109 Regulatory Asset			-	-	-	-	-	-	-
6	Prepaid Pension Asset	-	(29)	-	-	-	-	-	-	(29)
7	Unamortized OPEB Regulatory Asset									-
8	Total Investments in Assets	1,205	(29)	-	-	(1,105)	-	(13,405)	(8,969)	(22,303)
	Funds from Non-Investors									
9	Unamortized CIAC	-	(622)	-	-	-	-	-	-	(622)
10	Customer Advances	-	(1,591)	-	-	-	-	-	-	(1,591)
11	Customer Deposits	-	-	-			-			-
12	Accumulated Deferred Income Taxes	-	-	(1,376)	-	-	-	-	-	(1,376)
13	Unamortized ITC	-	-	-	(70)	-	-	-	-	(70)
14	OPEB Liability									-
15	Total Deductions	-	(2,213)	(1,376)	(70)	-	-	-	-	(3,659)
16	Difference	1,205	(2,242)	(1,376)	(70)	(1,105)	-	(13,405)	(8,969)	(25,962)
17	Working Cash at Present Rates	-	-	-	-	-	-	-	-	-
18	Rate Base at Present Rates	1,205	(2,242)	(1,376)	(70)	(1,105)	-	(13,405)	(8,969)	(25,962)
19	Change in Rate Base - Working Cash									-
20	Rate Base at Proposed Rates	$ 1,205	$ (2,242)	$ (1,376)	$ (70)	$ (1,105)	$ -	$ (13,405)	$ (8,969)	$ (25,962)

ADJUSTMENTS:

B-1 UPDATE OF PLANT ADDITIONS
B-2 UPDATE OF OTHER RATE BASE ITEMS
B-3 DEFERRED TAX RESERVE CORRECTIONS
B-4 UNAMORTIZED STATE ITC UPDATE
B-5 FUEL INVENTORIES
B-6 RESERVED FOR FUTURE USE
B-7 KEAHOLE: AFUDC ADJUSTMENT
B-8 KEAHOLE: LEGAL, LANDSCAPING & REZONING

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
UPDATE OF PLANT ADDITIONS
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	12/31/2005 AMOUNT	12/31/2006 AMOUNT	AVERAGE TEST YEAR AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	**Plant Additions Update Adjustment**				
2	HELCO As Filed Production Additions	CA T-3 WP-B-1.1	$ -	$ 7,692	$ 3,846
3	Revised Preliminary Actual Additions	CA T-3 WP-B-1.1	-	5,348	2,674
4	Production Additions Update		-	(2,344)	(1,172)
5	HELCO As Filed Transmission Additions	CA T-3 WP-B-1.1	-	7,390	3,695
6	Revised Preliminary Actual Additions	CA T-3 WP-B-1.1	-	8,640	4,320
7	Transmission Additions Update		-	1,250	625
8	HELCO As Filed Distribution Additions	CA T-3 WP-B-1.1	-	24,401	12,201
9	Revised Preliminary Actual Additions	CA T-3 WP-B-1.1	-	30,560	15,280
10	Distribution Additions Update		-	6,158	3,079
11	HELCO As Filed General Plant Additions	CA T-3 WP-B-1.1	-	5,836	2,918
12	Revised Preliminary Actual Additions	CA T-3 WP-B-1.1	-	3,181	1,591
13	General Plant Additions Update		-	(2,654)	(1,327)
14	Total Plant Additions Update		$ -	$ 2,410	$ 1,205

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
UPDATE OF OTHER RATE BASE ITEMS
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	REFERENCE	12/31/2005 AMOUNT	12/31/2006 AMOUNT	AVERAGE TEST YEAR AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	**Prepaid Pension Asset:**				
2	HELCO As Filed Pension Asset	HELCO-1601 & 920	$ 15,515	$ 12,829	$ 14,172
3	Revised Preliminary Actual Balances	CA-IR-464, p. 60	15,515	12,771	14,143
4	CA ADJUSTMENT TO UPDATE PREPAID PENSION ASSET				$ (29)
5	**Contributions In Aid of Construction:**				
6	HELCO As Filed Contributions in Aid of Construction	HELCO-1604	$ (56,925)	$ (58,149)	$ (57,537)
7	Revised Preliminary Actual Changes	CA-SIR-51	-	(1,244)	(622)
8	Adjustments for Post-TY Collections for 2006 Plant Additions	(a)	-		-
9	Revised Year-end Balance (add change)		(56,925)	(59,393)	(58,159)
10	CA ADJUSTMENT TO UPDATE CONTRIB. IN AID OF CONSTR.				$ (622)
11	**Customer Advances:**				
12	HELCO As Filed Customer Advances	HELCO-1605	$ (28,597)	$ (29,254)	$ (28,926)
13	Revised Preliminary Actual Balances	CA-SIR-51	-	(3,182)	(1,591)
14	Adjustments for Post-TY Collections for 2006 Plant Additions	(a)	-		-
15	Revised Year-end Balance (add change)		(28,597)	(32,436)	(30,517)
16	CA Adjustment to Update Customer Advances				$ (1,591)

Footnotes :

(a) At the time this filing was finalized, the CA was awaiting additional information from HELCO.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
DEFERRED TAX RESERVE CORRECTIONS
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	12/31/2005 DEFERRED TAX AMOUNT		12/31/2006 DEFERRED TAX AMOUNT		AVERAGE TEST YEAR AMOUNT	
	(A)	(B)		(C)		(D)		(E)
1	Adjustment to Update Deferred Taxes to Actual:			Note (a)				
2	Preliminary Actual Balances	CA-SIR-18, p.4	$	(25,440)	$	(25,630)	$	(25,535)
3	Deferred Taxes in HELCO Filing	HELCO-1305, p.3		(25,245)		(24,699)		(24,972)
4	Deferred Income Tax Adjustment to Update to Actual	Line 2 - Line 3	$	(195)	$	(931)	$	**(563)**
5	HELCO-conceded Deferred Tax Adjustments:							
6	Exclude Keahole Settlement Deferred Taxes	IR-447,p.2; 173,p4		included above				
7	True-up of Recorded ADIT for 2005 Tax Return	IR-447,p.2, p.4-5		(327)		-		(164)
8	Reclass Supp.Pension & Exec. Life Insurance	IR-447,p.2, p.6		(339)		(339)		(339)
9	Exclude Public Injuries ADIT	CA-IR-280b, 447,p.3		(120)		-		(60)
10	Exclude Gain on Mililani ADIT	CA-IR-280c, 447,p.3		10		-		5
11	Exclude HCPC Purchased Power ADIT	CA-IR-280g, 447,p.3		120		-		60
12	Exclude Gains/Losses (Partial) ADIT	CA-IR-280h, 447,p.3		12		-		6
13	Exclude Capitalized Hawaii Solar ADIT	CA-IR-280i, 447,p.3		(4)		-		(2)
14	Exclude HMSA Reserve ADIT	CA-IR-280m, 447,p.3		28		-		14
15	Exclude Puna Settlement ADIT	CA-IR-280r, 447,p.3		(64)		-		(32)
16	CA Adjustment to Exclude Conceded ADIT Items	Lines 6..15					$	**(512)**
17	Additional Consumer Advocate ADIT Adjustments:							
18	Bad Debt Deferred Taxes	CA-SIR-18, p.3,5		(364)		(411)		(388)
19	Exclude DSM Deferred Taxes	CA-SIR-18, p.3-6		(371)		(154)		(263)
20	Exclude IRP Deferred Taxes	CA-SIR-18, p.3-6		15		15		15
21	Exclude Energy Services Deferred Taxes	CA-SIR-18, p.3-6		(39)		(39)		(39)
22	Exclude Amort. Of Revenue Bond Interest Diff	CA-SIR-18, p.3-6		(43)		(35)		(39)
23	Exclude Revenue Bond Redemption Prem.	CA-SIR-18, p.3-6		425		398		412
24	CA Adjustment to Exclude Additional ADIT Items	Lines 18..23					$	**(302)**
25	Consumer Advocate Adjustment to Update, Correct and Restate Deferred Taxes (lines 3+16+24)						$	**(1,376)**

Footnotes :
(a) All amounts shown are combined Federal and State

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
UNAMORTIZED STATE ITC UPDATE
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	12/31/2005 STATE ITC DEFERRED	12/31/2006 STATE ITC DEFERRED	AVERAGE TEST YEAR STATE ITC
	(A)	(B)	(C)	(D)	(E)
1	Preliminary Actual Test Year State ITC Balances	CA-SIR-18, p.7	$ (11,555)	$ (12,175)	$ (11,865)
2	HELCO Estimated State ITC Balances	HELCO-1304	(11,555)	(12,035)	(11,795)
3	Consumer Advocate Adjustment to Update Deferred State ITC				**$ (70)**

Witness: Brosch/Herz

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
FUEL INVENTORIES
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Fuel Inventory Allowance Proposed by HELCO	HELCO-408	$ 8,266
2	Fuel Inventory Allowance Proposed by Consumer Advocate	CA-201	7,161
3	CA Adjustment to Restate Fuel Inventory Allowance		**$ (1,105)**

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
RESERVED FOR FUTURE USE
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT	% DISALLOWED	CA ADJUSTMENT
	(A)	(B)	(C)	(D)	(E)

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
KEAHOLE: AFUDC ADJUSTMENT
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	12/31/2005 AMOUNT	12/31/2006 AMOUNT	AVERAGE TEST YEAR AMOUNT	RATIO	TEST YEAR AFUDC ADJUSTMENT
	(A)	(B)	(C)	(D)	(E)	(F)
1	Other Production - Internal Combustion Engine					
2	341 Structures & Improvements	$ 170,881	$ 16,882,579	$ 8,526,730	7.27%	$ (1,047,589)
3	342 Fuel Holders, Producers & Accessories	429,341	9,290,867	4,860,104	4.14%	(597,110)
4	343 Prime Movers	63,410,654	42,012,643	52,711,649	44.95%	(6,476,122)
5	344 Generators	39,189,892	33,188,442	36,189,167	30.86%	(4,446,180)
6	345 Accessory Electric Equipment	1,692,543	2,424,478	2,058,511	1.76%	(252,907)
7	346 Misellaneous Power Plant Equip	3,363,431	1,869,278	2,616,355	2.23%	(321,444)
8	Total Other Production	108,256,742	105,668,287	106,962,515	91.21%	(13,141,352)
9	Transmission Plant					
10	352 Structures & Improvements -Substation	-	538,684	269,342	0.23%	(33,091)
11	353 Substation Equipment	540,293	10,188,958	5,364,626	4.57%	(659,095)
12	355 Poles & Fixtures	-	2,259	1,130	0.00%	(139)
13	356 Overhead Conductors & Devices	-	5,370	2,685	0.00%	(330)
14	Total Transmission	540,293	10,735,271	5,637,782	4.81%	(692,655)
15	Distribution Plant					
16	362 Substation Equipment	481,646	-	240,823	0.21%	(29,587)
17	Total Distribution	481,646	-	240,823	0.21%	(29,587)
18	General Plant	3,772,382	-	1,886,191	1.61%	(231,736)
19	390 Structures & Improvements	4,638,500	438,791	2,538,646	2.16%	(311,897)
20	397 Communication Equipment	8,410,882	438,791	4,424,837	3.77%	(543,633)
21	Total General Plant					
22	Total	$ 117,689,563 (a)	$ 116,842,349 (b)	$ 117,265,956	100.00%	$ (14,407,227) (c)
23	CA Adjustment to Remove Excess AFUDC Related				(000's)	$ (14,407)
24	to Keahole CT-4 & CT-5 from Plant In Service					
25	CA Adjustment to Remove Excess AFUDC	$ 668,470 (d)(e)	$ 1,336,940 (d)(e)	$ 1,002,705	(000's)	$ 1,003
26	Related to Keahole CT-4 & CT-5 from					
27	Accumulated Depreciation					

Footnotes :

(a) Source: HELCO response to CA-IR-163.

(b) Source: HELCO response to CA-SIR-44.

(c) AFUDC Adjustment -- Subject to Allocation

	Keahole CT-4	Keahole CT-5	Subtotal	Pre-CIP CT-4 & CT-5	Total
Allowed AFUDC	$ 5,889,144	$ 2,566,553	$ 8,455,697	$ -	$ 8,455,697
Less: Actual AFUDC 12/98	(14,099,896)	(7,561,191)	(21,661,087)	(1,201,837)	(22,862,924)
Total	$ (8,210,752)	$ (4,994,638)	$ (13,205,390)	$ (1,201,837)	$ (14,407,227)

Sources: HELCO response to CA-IR-190 & CA workpapers supporting AFUDC simulation model results.

(d) Source: CA Schedule C-17.

(e) Since Keahole CT-4 and CT-5 were added to plant in service in 2004 and HELCO starts recording book depreciation expense in the year following the plant addition, the 2006 accumulated depreciation adjustment two times the depreciation expense calculated on CA Schedule C-18 (i.e, calendar years 2005 and 2006) .

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
KEAHOLE: LEGAL, LANDSCAPING & REZONING
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	12/31/2005 AMOUNT	12/31/2006 AMOUNT	AVERAGE TEST YEAR AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	CA Proposed Adjustment				
2	Noise Abatement	(a)	$ (5,015,024)	$ (5,015,024)	$ (5,015,024)
3	Landscaping	(a)	(451,702)	(451,702)	(451,702)
4	Legal: Land Use Permit/Litigation	(a)	(3,153,981)	(3,153,981)	(3,153,981)
5	Subtotal -- Depreciable Production Plant		(8,620,707)	(8,620,707)	(8,620,707)
6	Keahole Land Rezoning (Land)	(a)	-	(1,958,392)	(979,196)
7	Total		$ (8,620,707)	$ (10,579,099)	$ (9,599,903)
8	CA Adjustment to Remove/Disallow Certain Legal,				**$ (9,600)**
9	Landscaping & Rezoning Costs Charged to				(000's)
10	Keahole CT-4 & CT-5 from Plant In Service				
11	CA Adjustment to Remove/Disallow Certain		$ 420,389	$ 840,778	**$ 631**
12	Legal, Landscaping & Rezoing Costs Related to		(b)(c)	(b)(c)	(000's)
13	Keahole CT-4 & CT-5 from Accumlated Depreciation				

Footnotes :

(a) ADJUSTMENT CALCULATION

	Amount	% Disallowed	Adjustment	
2004 Plant Additions:				
Noise Abatement	$ 10,030,048	50%	$ (5,015,024)	HELCO-1503, p.1
Landscaping	903,404	50%	(451,702)	CA-SIR-54
Legal: Land Use Permitting/Litigation	6,307,961	50%	(3,153,981)	CA-IR-386
Subtotal -- Depreciable Plant	17,241,413		(8,620,707)	
2006 Plant Additions:				
Keahole Land Rezoning	1,958,392	100%	(1,958,392)	CA-SIR-51
Total	$ 19,199,805		$ (10,579,099)	

Source: HELCO-1503, pp. 1, CA-SIR-54, CA-IR-386 & updated HELCO WP-1401, p. 3 (per CA-SIR-51).

(b) Source: CA Schedule C-17.

(c) Since Keahole CT-4 and CT-5 were added to plant in service in 2004 and HELCO starts recording book depreciation expense in the year following the plant addition, the 2006 accumulated depreciation adjustment two times the depreciation expense calculated on CA Schedule C-18 (i.e, calendar years 2005 and 2006) .

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SUMMARY OF OPERATING INCOME
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	HELCO PRO FORMA	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Electric Sales Revenue	$ 323,184	$ (4,385)	$ 318,799
2	Other Operating Revenue	904	21	925
3	Total Operating Revenues	324,089	(4,364)	319,724
4	Fuel	78,825	(3,710)	75,115
5	Purchased Power	117,318	(469)	116,849
6	Production	23,040	(2,000)	21,040
7	Transmission	2,401	(105)	2,296
8	Distribution	6,598	(353)	6,245
9	Customer Accounts	3,186	-	3,186
10	Allowance for Uncollectible Accounts	388	-	388
11	Customer Service	2,252	(764)	1,488
12	Administrative & General	12,471	189	12,660
13	Total O&M Expense	246,478	(7,212)	239,266
14	Depreciation and Amortization	29,374	(1,089)	28,285
15	Amortization of State ITC	(501)	-	(501)
16	Taxes Other than Income	30,293	(515)	29,778
17	Interest on Customer Deposits	56	-	56
18	Income Taxes	3,098	1,572	4,670
19	Total Operating Expenses	308,798	(7,244)	301,554
20	Operating Income	$ 15,291	$ 2,879	$ 18,170
		(a)	(b)	(c)

Footnotes:

(a) Source: HELCO-2101.
(b) From Page 4 of 4.
(c) Column B + Column C

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SUMMARY OF NOI ADJUSTMENTS
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE									
		C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ -	$ (4,385)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,385)
2	Other Operating Revenue	21	-	-	-	-	-	-	-	-	21
3	Total Operating Revenues	21	(4,385)	-	-	-	-	-	-	-	(4,364)
4	Fuel	-	(3,710)	-	-	-	-	-	-	-	(3,710)
5	Purchased Power		(469)								(469)
6	Production	-	-	(1,303)	(185)	(382)	(130)	-	-	-	(2,000)
7	Transmission	-	-	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	-	-	-	-	-	-	-	-	(168)	(168)
12	Administrative & General	-	-	-	-	-	-	-	-	-	-
13	Total O&M Expense	-	(4,179)	(1,303)	(185)	(382)	(130)	-	-	(168)	(6,347)
14	Depreciation and Amortization	-	-	-	-	-	-	-	-	-	-
15	Amortization of State ITC	-	-	-	-	-	-	-	-	-	-
16	Taxes Other than Income	-	(390)	-	-	-	-	-	-	-	(390)
17	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
18	Income Taxes	8	71	507	72	149	51	-	-	65	923
19	Total Operating Expenses	8	(4,498)	(796)	(113)	(233)	(79)	-	-	(103)	(5,814)
20	Operating Income	$ 13	$ 112	$ 796	$ 113	$ 233	$ 79	$ -	$ -	$ 103	$ 1,449

ADJUSTMENTS:
C-1 SERVICE ESTABLISHMENT CHARGE REVENUES
C-2 FUEL/PURCHASED POWER COST & ECAC REVENUE
C-3 PRODUCTION O&M CONCEDED ADJUSTMENTS
C-4 PRODUCTION O&M ACTUAL LABOR ADJUSTMENT
C-5 PRODUCTION O&M NON-LABOR MATERIALS ADJUSTMENT
C-6 OVERHAUL COST ADJUSTMENT - LPT REPLACEMENT
C-7 RESERVED FOR FUTURE USE
C-8 RESERVED FOR FUTURE USE
C-9 RECLASSIFICATION OF DSM EXPENSES

CA-101
Docket No. 05-0315
Schedule C
Page 2 of 4

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SUMMARY OF NOI ADJUSTMENTS
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE								SUBTOTAL
			C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ (4,385)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,385)
2	Other Operating Revenue	21	-	-	-	-	-	-	-	-	21
3	Total Operating Revenues	(4,364)	-	-	-	-	-	-	-	-	(4,364)
4	Fuel	(3,710)	-	-	-	-	-	-	-	-	(3,710)
5	Purchased Power	(469)									(469)
6	Production	(2,000)	-	-	-	-	-	-	-	-	(2,000)
7	Transmission	-	-	-	-	-	(16)	-	-	-	(16)
8	Distribution	-	-	-	-	-	(116)	-	-	-	(116)
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	(168)	(500)	(96)	-	-	-	-	-	-	(764)
12	Administrative & General	-	-	-	-	-	-	(131)	-	-	(131)
13	Total O&M Expense	(6,347)	(500)	(96)	-	-	(132)	(131)	-	-	(7,206)
14	Depreciation and Amortization	-	-	-	-	-	-	-	-	(668)	(668)
15	Amortization of State ITC	-	-	-	-	-	-	-	-	-	-
16	Taxes Other than Income	(390)	-	-	(100)	(25)	-	-	-	-	(515)
17	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
18	Income Taxes	923	195	37	39	10	51	51	-	260	1,566
19	Total Operating Expenses	(5,814)	(305)	(59)	(61)	(15)	(80)	(80)	-	(408)	(6,823)
20	Operating Income	$ 1,449	$ 305	$ 59	$ 61	$ 15	$ 80	$ 80	$ -	$ 408	$ 2,459

ADJUSTMENTS:
C-10 ELIMINATION OF PROPOSED REEPAH PROGRAM C(
C-11 CUSTOMER SERVICE PROJECT ADJUSTMENTS
C-12 PAYROLL TAX ADJUSTMENT
C-13 REVENUE TAX CORRECTION
C-14 T&D -- HELCO CORRECTIONS
C-15 T&D TRAINING ADJUSTMENT
C-16 RESERVED FOR FUTURE USE
C-17 KEAHOLE: AFUDC ADJUSTMENT

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Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SUMMARY OF NOI ADJUSTMENTS
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE								TOTAL
			C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Sales Revenue	$ (4,385)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,385)
2	Other Operating Revenue	21	-	-	-	-	-	-	-	-	21
3	Total Operating Revenues	(4,364)	-	-	-	-	-	-	-	-	(4,364)
4	Fuel	(3,710)	-	-	-	-	-	-	-	-	(3,710)
5	Purchased Power	(469)									(469)
6	Production	(2,000)	-	-	-	-	-	-	-	-	(2,000)
7	Transmission	(16)	-	(89)	-	-	-	-	-	-	(105)
8	Distribution	(116)	-	(237)	-	-	-	-	-	-	(353)
9	Customer Accounts	-	-	-	-	-	-	-	-	-	-
10	Allowance for Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
11	Customer Service	(764)	-	-	-	-	-	-	-	-	(764)
12	Administrative & General	(131)	-	-	-	321	-	-	-	-	189
13	Total O&M Expense	(7,206)	-	(326)	-	321	-	-	-	-	(7,212)
14	Depreciation and Amortization	(668)	(420)	-	-	-	-	-	-	-	(1,089)
15	Amortization of State ITC	-	-	-	-	-	-	-	-	-	-
16	Taxes Other than Income	(515)	-	-	-	-	-	-	-	-	(515)
17	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
18	Income Taxes	1,566	164	127	(160)	(125)	-	-	-	-	1,572
19	Total Operating Expenses	(6,823)	(257)	(199)	(160)	196	-	-	-	-	(7,244)
20	Operating Income	$ 2,459	$ 257	$ 199	$ 160	$ (196)	$ -	$ -	$ -	$ -	$ 2,879

C-18 KEAHOLE: LEGAL, LANDSCAPING & REZONING
C-19 T&D -- AVERAGE EMPLOYEE ADJUSTMENT
C-20 SECTION 199 INCOME TAX DEDUCTION
C-21 A&G -- HELCO CORRECTIONS
C-22
C-23
C-24
C-25

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Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SERVICE ESTABLISHMENT CHARGE REVENUES
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	*August 2006 Year to Date Actual Service Establishment Revenues*	CA-IR-317	$ 165.9
2	Factor to Expand for Full Year (12 months / 8 months)	12/8	1.5
3	Updated Estimate of Service Establishment Revenues	Line 1 * Line 2	249.0
4	Less: HELCO Proposed Service Establishment Revenues	HELCO-710	228.0
5	CA Adjustment to Restate Estimated Service Establishment Revenues	Line 3 - Line 4	**$ 21**

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
FUEL/PURCHASED POWER COST & ECAC REVENUE
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	HELCO PROPOSED AMOUNT	CONSUMER ADVOCATE AMOUNT	DIFFERENCE ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Fuel Oil Expense - Production Simulation	HELCO-401 / CA-301	$ 78,400	$ 74,762	$ (3,638)
2	Fuel Related Expense	HELCO-405 / CA-301	425	426	1
3	CA Adjustment to Fuel Expense	Line 1 + 2	78,825	75,188	$ (3,637)
4	Purchased Power - Energy Payments	HELCO-545 / CA-301	99,388	98,846	(542)
5	Purchased Power - Capacity Payments	HELCO-545 / CA-301	17,930	17,930	-
6	CA Adjustment to Purchased Power Expense	Line 4 + 5	117,318	116,776	$ (542)
7	Energy Cost Adjustment Rate / Present Rates (cents/kwh)	HELCO-303/CA-301	9.003	8.621	(0.382)
			HELCO GWH HELCO-201	Times ECAC Difference	ECAC Revenue Increase
8	Test Year Proposed Sales - Gigawatthours				
9	Residential R		435.4	(0.382)	$ (1,663)
10	Commercial G		98.0	(0.382)	(374)
11	Commercial J		354.9	(0.382)	(1,356)
12	Commercial H/K		17.2	(0.382)	(66)
13	Large Commercial P		238.1	(0.382)	(910)
14	Lighting F		4.4	(0.382)	(17)
15	Total Sales Volume		1,148.0		
16	CA Adjustment to ECAC Gross Revenues at CA Fuel/Energy Costs				$ (4,385)
			Tax Rate	Times ECAC Revenue Change	
17	Additional Revenue Taxes on Incremental ECAC Revenues				
18	Franchise Royalty Tax		2.500%	($4,385)	$ (110)
19	Public Service Company Tax		5.885%	($4,385)	(258)
20	Public Utility Commission Fees		0.500%	($4,385)	(22)
21	CA Adjustment to Taxes Other - Revenue Tax on ECAC Revenues				$ (390)

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
PRODUCTION O&M CONCEDED ADJUSTMENTS
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	ACCOUNT #	LABOR	NON-LABOR
	(A)	(B)	(C)	(D)	(E)
1	Company Conceded Adjustments - CA-IR-447 (page 2):				
2	*Removal of Technical Support Position*	*CA-IR-406*	*513*	*$ (89.4)*	
3	Cancel Hill Boiler Drawings Project	CA-IR-77, 340	512		$ (83.7)
4	Increase Continous Emissions Monitoring Fees	CA-IR-63, 331, 255	549		256.3
5	Reduce Distributed Generation Overhaul	CA-IR-256	553		(75.0)
6	Correct Outside Services Error	CA-IR-338	553		(80.2)
7	Normalize Diesel Engine Overhaul	CA-IR-255	553		(155.0)
8	Adjust Wauia Penstock Repairs	CA-IR-64, 343	543		(193.2)
9	*Adjust Puueo Penstock Repairs*	*CA-IR-64, 343*	*543*		*(86.8)*
10	Reduce Legal Services - Purchased Power	CA-IR-80	557		(93.0)
11	Correct Distribution of Labor to Capital	CA-IR-261, 409	513	(303.3)	
12	Adjust Hill 6 VFD Upgrades	CA-IR-254, 342	512		(150.0)
13	Adjust Overstated Materials Estimates	IR-63, 66, 334, 335	502		(249.3)
14	Sub-total Labor & Non-Labor Amounts	CA-IR-447, p.1		(392.7)	(909.9)
15	CA Adjustment Recognizing HELCO Conceded Production O&M Adjustments (Line 14, cols D+E rounded)				**$ (1,303)**

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
PRODUCTION O&M ACTUAL LABOR ADJUSTMENT
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	PROJECTED 2006 LABOR HELCO-531	ACTUAL 2006 LABOR CA-SIR-5	CA ADJUSTMENT Col. D - Col C
	(A)	(B)	(C)	(D)	(E)
1	Test Year Production Operations Labor Expense	HELCO-534	$ 6,054	$ 5,338	$ (716)
2	Test Year Production Maintenance Labor Expense	HELCO-541	3,228	2,834	(394)
3	Total Production Department Labor Expense		$9,282	$8,172	
4	Production Labor Adjustment - Actual versus Forecast				$ (1,110)
5	Less: Labor Expense Conceded Adjustments (Schedule C-3, line 14)				392.7
6	Less: Outside Temporary Services (EE503) Not Budgeted	CA-SIR-14, Att.2			532.8
7	CA Adjustment to Restate Test Year Production O&M Labor to 2006 Actual				$ (185)

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
PRODUCTION O&M NON-LABOR MATERIALS ADJUSTMENT
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	HISTORICAL EXPENSE AMOUNT	HISTORICAL ERROR CORRECTION	CORRECTED HISTORICAL AMOUNTS
	(A)	(B)	(C)	(D)	(E)
1	Actual Production Miscellaneous Materials Expense:			Note (a)	
2	2001	CA-SIR-10, Att.1 p11	$1,076		$1,076
3	2002	"	1,287		1,287
4	2003	"	1,529		1,529
5	2004	"	2,553	(194)	2,359
6	2005	"	1,520	194	1,714
7	2006	"	1,875		1,875
8	Three Year Average of Historical Actual 2004-2006 (Corrected) Materials Expenses				$1,983
9	Less: HELCO Projected Production Materials	CA-IR-2, HELCO T-5 Att. 2A, p.21			2,614
10	Less: HELCO Conceded Adjustments for Overforecasting	Schedule C-3			(249)
11	Net Production O&M Materials in HELCO Filing (after Conceded Adjustments)				2,365
12	CA Adjustment to Correct Overstated Materials Expenses	Line 8 - Line 11			$ (382)

Footnotes:

(a) A $193,644 negative entry was recorded in 2005 to reverse an incorrect reclassification of a 2004 project involving Kanoelehua 4KV switchgear, as more fully explained in CA-IR-336, part d. This adjustment is needed to restate recorded values to correct for this error.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
OVERHAUL COST ADJUSTMENT - LPT REPLACEMENT
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HELCO Forecast Normalization Adjustment - CT-4 LPT Replacement	T-5, page 58	$ 65
2	HELCO Forecast Normalization Adjustment - CT-5 LPT Replacement	"	65
3	CA Adjustment to Remove Speculative LPT Turbine Replacements	Lines 1 + 2	$ (130)

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
RESERVED FOR FUTURE USE
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	PROJECTED 2006 LABOR HELCO-701	ACTUAL 2006 LABOR CA-SIR-5, p26	CA ADJUSTMENT Col. D - Col C
	(A)	(B)	(C)	(D)	(E)
1					
2					
3					
4					
5					

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
RESERVED FOR FUTURE USE
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	PROJECTED 2006 LABOR HELCO-801	ACTUAL 2006 LABOR CA-SIR-5,p27	CA ADJUSTMENT Col. D - Col C
	(A)	(B)	(C)	(D)	(E)
1					
2					
3					
4					
5					

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
RECLASSIFICATION OF DSM EXPENSES
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	HELCO-WP-101 REFERENCE	ACTIVITY 713 EXPENSE AMOUNTS
	(A)	(B)	(C)
1	Test Year Proposed DSM Administration Costs - Base Rates		
2	Customer Assistance (Account 910) Energy Services Dept Direct Labor	WP-101(F) p.658	$ 102
3	Customers Assistance (Account 910) Commercial Services Dept Direct Labor	" p.659	41
4	Customer Assistance (Account 910) Energy Services Dept-Labor Overhead	WP-101(H) page 863	19
5	Customers Assistance (Account 910) Commercial Services Dept-Labor Overhead	" page 864	6
6	Total Base Rate DSM Program Administration & Implementation Expense		$ 168
7	Consumer Advocate Adjustment to Reclassify DSM Administration Costs for Surcharge Recovery		**$ (168)**

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
ELIMINATION OF PROPOSED REEPAH PROGRAM COSTS
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HELCO Adjustment - Affordable Homes Renewable Energy Program	HELCO-WP-801p.7	$ 500
2	Consumer Advocate Adjustment to Eliminate Proposed REEPAH Funding		**$ (500)**

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
CUSTOMER SERVICE PROJECT ADJUSTMENTS
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	EXPENSE AMOUNT
	(A)	(B)	(C)
1	CHP Project Support from HECO - Revised Cost Estimate	CA-IR-447	$ 46
2	Less: Test Year Cost Projection	CA-IR-447	75
3	Consumer Advocate Adjustment for CHP Project Support	Line 1 - Line 2	**(29)**
4	Customer Service Projects - Actual Billings YTD October 2006	CA-IR-357, p.5	22
5	Times 12 / 10 (months) to Annualize Actual Spending	Factor 12/10	1.200
6	Actual Spending at Annualized Rate - Customer Service Projects	Line 4 * Line 5	26
7	Less: Test Year Customer Service Project Cost Estimates (Non-labor)	CA-IR-357, p.5	93
8	Consumer Advocate Adjustment for Customer Service Project Support	Line 6 - Line 7	**(67)**
9	Consumer Advocate Adjustment to Customer Service Project Costs	Line 3 + Line 8	**$ (96)**

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
PAYROLL TAX ADJUSTMENT
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Payroll Adjustments Proposed by Consumer Advocate:		
2	HELCO Conceded Production O&M Labor Adjustments	Schedule C-3	$ (393)
3	Consumer Advocate Production O&M Labor Adjustment	Schedule C-4	(185)
4	Consumer Advocate DSM Labor Reclassification (Note b)	Schedule C-9	(168)
5	HELCO Conceded T&D O&M Labor Adjustment	Schedule C-14	(107)
6	Consumer Advocate T&D O&M Labor Adjustment	Schedule C-19	(326)
7	Total Consumer Advocate Labor Adjustments		(1,179)
8	Total Test Year Forecasted Labor Costs	Note (a)	18,413
9	Consumer Advocate Labor Adjustment Percentage	Line 11/Line 12	-6.4%
10	HELCO Proposed FICA/Medicare Tax	HELCO-1301	$ 1,442
11	Consumer Advocate FICA/Medicare Adjustment	Line 13 * Line 14	**$ (92)**
12	Test Year-end Actual Number of Employees	CA-SIR-43	340
13	Test Year-end Estimated Number of Employees	HELCO-WP-1301p3	376
14	Employee Actual/Forecast Ratio		0.9043
15	HELCO Proposed FUTA & SUTA Tax	HELCO-1301	$ 88
16	Consumer Advocate Revised FUTA/SUTA Tax Expense	Line 18 * Line 19	80
17	Consumer Advocate FUTA/SUTA Tax Adjustment	Line 20 - Line 19	**$ (8)**
18	Consumer Advocate Adjustment to Payroll Taxes	Line 15 + Line 21	**$ (100)**

Footnotes :

(a) Summary of HELCO Test Year Labor Expense:

Production	HELCO-534,541	$9,282
Transmission	HELCO-603, p.1	929
Distribution	HELCO-603, p.2	2,467
Customer Accts	HELCO-701	1,966
Customer Svc.	HELCO-801p3	762
Admin. & General	HELCO-901p8	3,007
Total HELCO-Proposed Labor Expense		$18,413

(b) The DSM reclassification is not a labor cost disallowance, but is needed here to reclassify payroll taxes associated with DSM base labor.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
REVENUE TAX CORRECTION
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	PSC TAX AT PRESENT RATES AMOUNT	PUC FEE AT PRESENT RATES AMOUNT
	(A)	(B)	(C)	(D)
1	Omitted Bad Debt Deduction Amount	HELCO-705	$ 388	$ 388
2	PSC Tax / PUC Fee Rates	CA-IR-285	5.8850%	0.5000%
3	Tax Savings Upon Recognition of Bad Debt Deduction	Line 1 * Line 2	23	2
4	Consumer Advocate Adjustment to Correct Revenue Taxes			$ (25)

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
T&D – HELCO CORRECTIONS
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	TRANSMISSION	DISTRIBUTION	TOTAL
	(A)	(B)	(C)	(D)
1	Transformer Mounting Plates	$ -	$ 62,065	$ 62,065
2	Manhole Cover Replacements		5,872	5,872
3	Abandoned Capital Projects	(5,065)	(87,394)	(92,459)
4	Open Trouble Inspector Positions	(11,034)	(96,050)	(107,084)
5	Total	$ (16,099) (a)	$ (115,507) (a)	$ (131,606)
6	Consumer Advocate Adjustment to Recognize HELCO Correction to T&D Expense	(000's)		$ (132)

Footnotes:

(a) Source: HELCO T-6 response to CA-IR-447.

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Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
T&D TRAINING ADJUSTMENT
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	REFERENCE	ACCOUNT 925	ACCOUNT 926	TOTAL
	(A)	(B)	(C)	(D)	(E)
1	Actual 2006 T&D Training Expense	(a)	$ 278	$ 436	$ 715
2	Less: HELCO Revised T&D Training Forecast	(b)	(386)	(460)	(846)
3 4	CA Adjustment to Recognize T&D Training Expense at 2006 Actual Levels		$ (108)	$ (24)	$ (131)

Footnotes:

(a) Source: HELCO response to CA-SIR-37, revised 2/6/07.

(b) HELCO Revised T&D Training Forecast:

	A/C 925	A/C 926	Total	Sources
HELCO Indentified Orig TY FCST	$ 289,512	$ 269,317	$ 558,829	CA-IR-447
HELCO Corrections	(63,459)	(45,227)	(108,686)	CA-SIR-35
Actual Original TY FCST	226,053	224,090	450,143	CA-SIR-35
HELCO Proposed Safety Incr.	166,086	238,712	404,798	CA-IR-447
Subtotal	392,139	462,802	854,941	
Trouble Inspector Correction	(5,739)	(2,902)	(8,641)	CA-SIR-35
HELCO Revised Safety Forecast	$ 386,400	$ 459,900	$ 846,300	CA-SIR-37

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
RESERVED FOR FUTURE USE
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1			
2			
3			

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
KEAHOLE: AFUDC ADJUSTMENT
FORECAST 2006 TEST YEAR

Exhibit CA-101
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Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AFUDC ADJUSTMENT	BOOK DEPRECIATION RATE	2006 BOOK DEPRECIATION EXPENSE	ACCUMULATED DEPRECIATION 12/31/2005 AMOUNT	ACCUMULATED DEPRECIATION 12/31/2006 AMOUNT	ACCUMULATED DEPRECIATION AVERAGE TEST YEAR
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Other Production - Internal Combustion Engine							
2	341 Structures & Improvements	(b)	$ (1,047,589)	2.70%	$ (28,285)	$ 28,285	$ 56,570	$ 42,427
3	342 Fuel Holders, Producers & Accessories	(b)	(597,110)	6.90%	(41,201)	41,201	82,401	61,801
4	343 Prime Movers	(b)	(6,476,122)	4.80%	(310,854)	310,854	621,708	466,281
5	344 Generators	(b)	(4,446,180)	5.00%	(222,309)	222,309	444,618	333,463
6	345 Accessory Electric Equipment	(b)	(252,907)	4.40%	(11,128)	11,128	22,256	16,692
7	346 Misellaneous Power Plant Equip	(b)	(321,444)	5.00%	(16,072)	16,072	32,144	24,108
8	Total Other Production		(13,141,352)		(629,848)	629,848	1,259,697	944,773
9	Transmission Plant							
10	352 Structures & Improvements -Substation	(c)	(33,091)	2.60%	(860)	860	1,721	1,291
11	353 Substation Equipment	(b)(c)	(659,095)	2.50%	(16,477)	16,477	32,955	24,716
12	355 Poles & Fixtures	(c)	(139)	4.20%	(6)	6	12	9
13	356 Overhead Conductors & Devices	(c)	(330)	3.90%	(13)	13	26	19
14	Total Transmission		(692,655)		(17,356)	17,356	34,713	26,035
15	Distribution Plant							
16	362 Substation Equipment	(b)(c)	(29,587)	3.80%	(1,124)	1,124	2,249	1,686
17	Total Distribution		(29,587)		(1,124)	1,124	2,249	1,686
18	General Plant	(b)(c)	(231,736)	2.50%	(5,793)	5,793	11,587	8,690
19	390 Structures & Improvements	(b)(c)	(311,897)	4.60%	(14,347)	14,347	28,694	21,521
20	397 Communication Equipment		(543,633)		(20,141)	20,141	40,281	30,211
21	Total General Plant							
22	Total		$ (14,407,227) (a)		$ (668,470)	$ 668,470	$ 1,336,940	$ 1,002,705
23	CA Adjustment to Remove Depreciation on							
24	Keahole AFUDC Adjustment From 2006 Test Year			(000's)	$ (668)			

Footnotes:

(a) Source: CA Schedule B-7, AFUDC Adjustment.
(b) Source: Book depreciation rates per HELCO-WP-1206, p. 2.
(c) Source: Book depreciation rates per HELCO-WP-1201, pp. 2-3.

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Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
KEAHOLE: LEGAL, LANDSCAPING & REZONING
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT	ACCUMULATED DEPRECIATION 12/31/2005 AMOUNT	ACCUMULATED DEPRECIATION 12/31/2006 AMOUNT	ACCUMULATED DEPRECIATION AVERAGE TEST YEAR
	(A)	(B)	(C)	(D)	(E)	(F)
1	Production Plant Adjustment -- Keahole CT-4 & CT-5	(a)	$ (8,620,707)			
2	Composite Depreciation Rate -- Keahole Production	(b)	4.88%			
3	2006 Book Depreciation Expense		$ (420,389)	$ 420,389	$ 840,778	$ 630,583
4 5 6	CA Adjustment to Remove Depreciation on Certain Keahole Legal, Landscaping & *Rezoning Costs From 2006 Test Year*	*(000's)*	*$ (420)*			

Footnotes:

(a) Source: CA Schedule B-8.

(b) Other Production - Internal Combustion Engine

2005 Book Depreciation -- Keahole CT-4 & CT-5	$ 4,666,392
2004 Plant Additions -- Keahole CT-4 & CT-5	95,691,411
Composite Depreciation Rate -- Keahole Production	4.88%

Source: HELCO WP-1206, p. 2.

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
T&D -- AVERAGE EMPLOYEE ADJUSTMENT
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION		REFERENCE	LABOR CLASS	ADJUSTMENT AMOUNT
	(A)		(B)	(C)	(D)
1	Distribution Divisions				
2	HDA	Administration	Note (a)		$ -
3	HDC	Technical	"	D_TechCrew	(43,417)
4	HDH	Hilo C&M	"	D_Crew	(33,109)
5	HDK	Kona C&M	"	D_Crew	(179,663)
6	HDR	Operations	"		-
7	HDS	Stores	"		-
8	HDW	Waimea C&M	"		(70,287)
9		Total			$ (326,476)
10	*CA Adjustment to Reflect Average 2006 T&D Employees*			*(000's)*	***$ (326)***

Footnotes:
(a) CA T-3 WP-19.1.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
SECTION 199 INCOME TAX DEDUCTION
FORECAST 2006 TEST YEAR
$000

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Estimated Taxable Income for Generation Activity (HELCO Proposed Rates)	CA-SIR-23, p.3	$ 17,369
2	Adjustment for Difference in Return Allowed on Generation Activity		
3	HELCO Weighted Cost of Equity Capital	Schedule D	5.72%
4	CA Weighted Cost of Equity Capital	Schedule D	5.02%
5	Adjustment Factor for Return Allowed Generation Assets	Line 4 / Line 3	0.87762
6	Estimated Taxable Income for Generation at CA Proposed Rates	Line 1 * Line 5	$15,243
7	Estimated Domestic Production Activities Deduction at 3%	Note (a)	$457
8	CA Adjustment to Reflect Federal Income Tax Savings - Section 1999	Line 7 * 35%	**$ (160)**

Footnote:

(a) A 6 percent Section 199 Deduction is effective 1/1/2007, but has not been recognized to maintain matching with the average 2006 test year used in setting utility rates. If any adjustments to recognize year-end annualization adjustments or changes occurring in 2007, this adjustment should be doubled to account for the 2007 deduction level at six percent.

Witness: S. Carver

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
A&G -- HELCO CORRECTIONS
FORECAST 2006 TEST YEAR

LINE NO.		DESCRIPTION (A)	AMOUNT (B)
1	92100	Correct estimate for MINCOM processing fees.	$ 159
2	92100	Correct estimate for copying machine costs.	(30)
3	92100	Update Engineering Dept microfilming costs to sustainable level.	(40)
4	92302	Update KPMG SOX 404 and Financial audit costs.	(17)
5	92303	Defer HR Suites Phase 1 costs to 2007.	(127)
6	92303	*Adjust LOC Fees - Syndicated Credit Facility vs Multiple Billateral.*	(1)
7	92501	Update Distribution Dept Safety Training costs.	160
8	92501	Update Production Dept Safety Training costs.	(73)
9	92603	Update Qualified Pension Plan estimate.	58
10	92606	Update Distribution Dept Non-Safety Training costs.	236
11	92606	Adjust Benefit Costs for T&D Employee Benefits Labor Costs.	(14)
12	92609	Update Other Post-Retirement Benefits estimate.	(49)
13	92800	Update for A&G & Act 162 (ECAC) Consultant costs.	41
14	93200	Adjust Building & Grounds Maintenance costs based on 5-Year average.	16
15	CA Adjustment to Recognize Helco Proposed Revisions		
16	to Administrative & General Expense Accounts		$ 321 (a)

Footnote:
(a) Source: HELCO T-9 response to CA-IR-447, p. 7.

Witness: Carver/Parcell

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
CAPITAL STRUCTURE & COSTS
FORECAST 2006 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	AMOUNT IN THOUSANDS	PERCENT OF TOTAL	EARNINGS REQMTS	WEIGHTED EARNINGS REQMTS
	(A)	(B)	(C)	(D)	(E)
	HELCO Proposed (a)				
1	Short-Term Debt	$28,793	7.59%	5.00%	0.38%
2	Long-Term Debt	117,455	30.96%	5.90%	1.83%
3	Taxable Debt	24,569	6.48%	6.20%	0.40%
4	Hybrid Securities	9,152	2.41%	7.50%	0.18%
5	Preferred Stock	6,563	1.73%	8.37%	0.14%
6	Common Equity	192,862	50.83%	11.25%	5.72%
7	Total Capitalization	$379,394	100.00%		**8.65%**
	CA Proposed (b)				
8	Short-Term Debt	$28,793	7.59%	5.00%	0.38%
9	Long-Term Debt	117,455	30.96%	5.90%	1.83%
10	Taxable Debt	24,569	6.48%	6.20%	0.40%
11	Hybrid Securities	9,152	2.41%	7.50%	0.18%
12	Preferred Stock	6,563	1.73%	8.37%	0.14%
13	Common Equity (midpoint)	192,862	50.83%	9.88%	5.02%
14	Total Capitalization	$379,394	100.00%		**7.95%**

Footnotes :

(a) Source: HELCO-WP-2101, p. 3.

(b) Source: Exhibit CA-413.
The recommended range for the cost of common equity is 9.5% *to* 10.25%, *with a* midpoint of 9.875%. The CA's proposed weighted cost of capital ranges from 7.76% to 8.14%, with a midpoint of 7.95%.

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
RECONCILIATION OF POSITIONS
FORECAST 2006 TEST YEAR

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**Asserted Revenue Requirement**			$ 29,931
2	SCH. B	**Return Difference At HELCO Rate Base** (before pro forma working cash)	$ 373,100	-1.260%	(4,701)
3		Subtotal Revenue Requirement			$ 25,230
				PRE-TAX RETURN	
4		RATE BASE ADJUSTMENTS			
5	B-1	UPDATE OF PLANT ADDITIONS	1,205	13.58%	$164
6	B-2	UPDATE OF OTHER RATE BASE ITEMS	(2,242)	13.58%	(304)
7	B-3	DEFERRED TAX RESERVE CORRECTIONS	(1,376)	13.58%	(187)
8	B-4	UNAMORTIZED STATE ITC UPDATE	(70)	13.58%	(10)
9	B-5	FUEL INVENTORIES	(1,105)	13.58%	(150)
10	B-6	RESERVED FOR FUTURE USE	0	13.58%	0
11	B-7	KEAHOLE: AFUDC ADJUSTMENT	(13,405)	13.58%	(1,820)
12	B-8	KEAHOLE: LEGAL, LANDSCAPING & REZONING	(8,969)	13.58%	(1,218)
13	B-9	0	0	13.58%	0
14	B-10	0	0	13.58%	0
15	B-11	0	0	13.58%	0
16	B-12	0	0	13.58%	0
17	B-13	0	0	13.58%	0
18	B-14	0	0	13.58%	0
19	B-15	0	0	13.58%	0
20	B-16	0	0	13.58%	0
21	B-17	0	0	13.58%	0
22	B-18	0	0	13.58%	0
23	B-19	0	0	13.58%	0
24	B-20	0	0	13.58%	0
13		Total Value of Rate Base Adustments	(25,962)		(3,526)
14		Rate Base Recommendation (before pro forma working cash)	$ 347,139		
15		Change in Working Cash at Proposed Rates (HELCO vs CA)	$ 1,760.07	14.84%	261
16		Rate Base With Working Cash Difference			$ (3,265)
				REVENUE CONVERSION MULTIPLIER	
17	SCH. A	**Adjusted Net Operating Income**	$ 15,291		
		NET OPERATING INCOME ADJUSTMENTS			
18	C-1	SERVICE ESTABLISHMENT CHARGE REVENUES	13	1.7988	($23)
19	C-2	FUEL/PURCHASED POWER COST & ECAC REVENUE	112	1.7988	(202)
20	C-3	PRODUCTION O&M CONCEDED ADJUSTMENTS	796	1.7988	(1,432)
21	C-4	PRODUCTION O&M ACTUAL LABOR ADJUSTMENT	113	1.7988	(203)
22	C-5	PRODUCTION O&M NON-LABOR MATERIALS ADJUSTMENT	233	1.7988	(420)
23	C-6	OVERHAUL COST ADJUSTMENT - LPT REPLACEMENT	79	1.7988	(143)
24	C-7	RESERVED FOR FUTURE USE	0	1.7988	0
25	C-8	RESERVED FOR FUTURE USE	0	1.7988	0
26	C-9	RECLASSIFICATION OF DSM EXPENSES	103	1.7988	(185)
27	C-10	ELIMINATION OF PROPOSED REEPAH PROGRAM COSTS	305	1.7988	(549)
28	C-11	CUSTOMER SERVICE PROJECT ADJUSTMENTS	59	1.7988	(105)
29	C-12	PAYROLL TAX ADJUSTMENT	61	1.7988	(110)
30	C-13	REVENUE TAX CORRECTION	15	1.7988	(27)
31	C-14	T&D -- HELCO CORRECTIONS	80	1.7988	(145)
32	C-15	T&D TRAINING ADJUSTMENT	80	1.7988	(144)
33	C-16	RESERVED FOR FUTURE USE	0	1.7988	0
34	C-17	KEAHOLE: AFUDC ADJUSTMENT	408	1.7988	(735)
35	C-18	KEAHOLE: LEGAL, LANDSCAPING & REZONING	257	1.7988	(462)
36	C-19	T&D -- AVERAGE EMPLOYEE ADJUSTMENT	199	1.7988	(359)
37	C-20	SECTION 199 INCOME TAX DEDUCTION	160	1.7988	(288)
38	C-21	A&G -- HELCO CORRECTIONS	(196)	1.7988	352
39		Total Value of Net Operating Income Adj.	2,879		$ (5,160)
40	SCH. A	Net Operating Income Recommendation	$ 18,170		
41		RECONCILED REVENUE REQUIREMENT			$ 16,786
42		UNRECONCILED DIFFERENCE			(143)
43	SCH. A	REVENUE REQUIREMENT RECOMMENDATION			$ 16,643

Witness: M. Brosch

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
CALCULATION OF PRE-TAX RETURN
FORECAST 2006 TEST YEAR

LINE NO.	DESCRIPTION	WEIGHTED COST (SCH. D)	REVENUE CONVERSION MULTIPLIER (a) (b)	PRETAX RETURN
	(A)	(B)	(C)	(D)
	RETURN PER HELCO			
1	Short-Term Debt	0.38%	1.7988	0.684%
2	Long-Term Debt	1.83%	1.7988	3.292%
3	Hybrid Securities	0.18%	1.7988	0.324%
4	Preferred Stock	0.14%	1.7988	0.252%
5	Common Equity	5.72%	1.7988	10.289%
6	Total Capitalization	8.25%		14.840%
	RETURN PER CA			
7	Short-Term Debt	0.38%	1.7988	0.684%
8	Long-Term Debt	1.83%	1.7988	3.292%
9	Hybrid Securities	0.18%	1.7988	0.324%
10	Preferred Stock	0.14%	1.7988	0.252%
11	Common Equity (midpoint)	5.02%	1.7988	9.030%
12	Total Capitalization	7.55%		13.581%
13	DIFFERENCE IN PRE-TAX RETURNS			-1.260%

Source: CA Schedules D & A-1.

CA-T-2
DOCKET NO. 05-0315

DIRECT TESTIMONY AND EXHIBITS

OF

JOSEPH A. HERZ

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: **Fuel and Purchased Power Expense, Generation Efficiency Factor (Sales Heat Rate), Fuel Inventory, Energy Cost Adjustment Factor and Power Factor Adjustment in Rate Design**

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TABLE OF EXHIBITS

DIRECT TESTIMONY OF JOSEPH A. HERZ, P.E.

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, POSITION AND PLACE OF EMPLOYMENT.

A. My name is Joseph A. Herz. I am employed by Sawvel and Associates, Inc. (Sawvel). I am an owner and Vice President of Sawvel, which is an independent consulting firm. Sawvel is located at 100 East Main Cross Street, Suite 300, Findlay, Ohio 45840.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. Exhibit CA-200 summarizes my professional experience and educational background.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Division of Consumer Advocacy ("Consumer Advocate" or "CA"), who is a participant in this proceeding to represent, advance and protect the interests of Hawaii's electric utility ratepayers.

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN REGULATORY ENGAGEMENTS BEFORE THE HAWAII PUBLIC UTILITIES COMMISSION ("COMMISSION") ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes. I testified on behalf of the Consumer Advocate in rate case proceedings involving Hawaiian Electric Company, Inc. ("HECO" or "Company") Docket Nos. 7766 and 04-0113, Hawaii Electric Light Company, Inc. ("HELCO") Docket Nos. 7764, 97-0420 and 99-0207 and Kauai Electric Division ("KED") Docket No. 94-0097. In addition to these rate case engagements, I assisted the Consumer Advocate with its analysis, Statement of Position and/or testimony in various IPP purchase power agreements, IRP planning, resource additions and transmission improvements involving HELCO (Docket Nos. 7623, 97-0349, 98-0013, 99-0346 and 99-0355) and avoided energy cost calculation for a proposed wind facility on Kauai (Docket No. 01-0005). I testified on behalf of the Consumer Advocate in the Commission's generic investigation of distributed generation ("DG") in Hawaii (Docket No. 03-0371). Most recently, I testified on behalf of the Consumer Advocate in HECO's application to commit funds for a 110 MW Combustion Turbine to be sited in the Campbell Industrial Park area (Docket No. 05-0145) and assisted the Consumer Advocate in reaching a stipulated agreement with HECO and the Department of Defense in Docket No. 7310.

Q. WHAT ARE THE FUNCTIONAL AREAS OF THE CONSUMER ADVOCATE'S PRESENTATION IN THIS DOCKET, FOR WHICH YOU ARE DIRECTLY RESPONSIBLE?

A. My direct testimony provides the Consumer Advocate's position on HELCO's 2006 estimated test year fuel and purchased power expense, generation efficiency factor (sales heat rate), fuel inventory and energy cost factor at current rates based on the production simulation results described later in this testimony. In addition, my testimony addresses the power factor adjustment in rate design.

Q. WHAT MATERIALS DID YOU REVIEW AS PART OF YOUR PREPARATION FOR THIS FILING?

A. The materials that I have reviewed are HELCO's application, written direct testimonies, exhibits and workpapers, as well as the responses to various information requests submitted by the Consumer Advocate.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring Exhibits CA-200 through CA-218. A listing and description of my exhibits is provided in the table of contents at the beginning of this testimony.

II. SUMMARY OF RECOMMENDATIONS.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. It is my recommendation, based on the results of the independent production simulation that I conducted of HELCO's system, that the Commission make the adjustments shown in Exhibit CA-201, and summarized below, to HELCO's 2006 test year direct testimony filing projections:

1. Fuel and Purchased Power Expenses – Using HELCO's fuel prices from February 2006, the recommended fuel expense and purchased power expense for the 2006 test year should be decreased by $3,637,000 and $542,000, respectively (see CA-201, Lines 3 and 6).

   The Consumer Advocate's production simulation that was used to develop the recommended fuel and purchased power expense adjustments incorporated the following adjustments or differences to HELCO's February 2006 direct testimony filing:

   a. Puna CT-3, Keahole CT-4, and Keahole CT-5 hourly Variable Operation and Maintenance components were updated in accordance with HELCO's response to CA-IR-448. The Company's production simulation results may not reflect these updated components.

   b. Shipman 3 and 4 were modeled to be in operation from 7:00 am to 9:00 pm as set forth in HELCO-WP-404, Page 53. The

Company's production simulation results assumed that Shipman 3 and 4 were operating from 7:00 am to 8:00 pm;

c. Kanoelehua D11, Panaewa, Ouli, Punaluu, and Kapua were allowed to run below their minimum generation levels (2 MW for Kanoelehua and 1 MW for the others);

d. Waimea D12-D14, Kanoelehua D15-D17, and Keahole D21-D23 were modeled to run at 2.5 MW per hour as stated in the direct testimony filing. The Company's production simulation results did not reflect this level of operation;

e. Puna Geothermal Venture (PGV) was modeled with a generating level of 27.8 MW during its on-peak period and 26.8 MW during its off-peak period as set forth in HELCO Direct Testimony (T-5). It is unclear to us that the Company modeled PGV in this way as explained later in my testimony;

f. In the Company's production simulation, generating units Shipman 3 and 4, Hill 5, Puna Steam, Kanoelehua CT-1, Keahole CT-2, Puna CT-3, Keahole CT-4 (economic dispatch component), and Keahole CT-5 (economic dispatch component) were allowed to generate below their minimum generation, as stated in HELCO-WP-404, Pages 24-25. My production simulation model did not allow these units to dispatch below their minimum generation levels.

The Consumer Advocate's production simulation incorporated the following key assumptions:

a. To calculate HEP's fuel component, I used the formula provided in the Power Purchase Agreement with HEP. The Company calculated the fuel cost using a heat rate formula that was intended to result in the same fuel cost as the fuel component formula in the Power Purchase Agreement with HEP. It appears that these two formulas do not result in the same fuel cost. This is explained later in my testimony.

b. The fuel prices used in the Company's direct testimony filing were used to calculate the Consumer Advocate's fuel oil expenses;

c. Generating unit heat rate constants stated in the Company's direct testimony filing were used to calculate heat rates in the production simulation;

d. The Company's estimation of losses of 8.14% were reasonable and thus, was not modified nor was the system energy requirement;

e. I accepted the Company's estimation of Company Use energy;

f. The Company's retail sales estimates appear reasonable as discussed in CA-T-1.

Each of the above items is described in greater detail in Section III of my testimony. It should be noted that the Consumer Advocate's production simulation produced different dispatch results for some generating units than the Company's model. We have not reconciled these differences with HELCO, however, the Consumer Advocate hopes to be able to reconcile production simulation modeling differences with the Company prior to the evidentiary hearing in this proceeding. This matter is also explained in more detail in Section III of my testimony.

2. Sales Heat Rate – Based on the production cost simulation which the Consumer Advocate has conducted using the estimated 2006 test-year data described above, the Fixed Efficiency Factors for the 2006 test year should be as follows:

Fixed Efficiency Factors	mmBtu/kWh sales	Adjustment
Sales Heat Rate - Steam	0.015631	(0.000009)
Sales Heat Rate - Diesel	0.013089	(0.000538)
Sales Heat Rate - Other	0.014803	0.000019
Weighted Efficiency Factor	0.014869	(0.000005)

Source: CA-201, Line 7

The Adjustment column indicates that the steam sales heat rate should be decreased 0.000009, the diesel sales heat rate should be decreased 0.000538, and the other sales heat rate should be increased 0.000019 from HELCO's recommended sales heat rates. The weighted efficiency factor decreased 0.000005 MMBtu per kWh to the Weighted Efficiency Factor recommended in HELCO's direct testimony filing. The efficiency factors should be incorporated in the Energy Cost Adjustment Clause resulting from this proceeding (see CA-201, Line 7).

3. Fuel Inventory – Utilizing HELCO's requested 24-day industrial fuel oil inventory level, and HELCO's requested 30-day level of diesel fuel oil inventory, the Consumer Advocate's recommended test year fuel consumption and HELCO's February 2006 fuel prices, the recommended fuel inventory to be included in the test year rate base is $7,161,000 a decrease of $1,105,000 to HELCO's test year filing of $8,266,000 (see CA-201, Line 8).

4. ECA Factor at Current Rates – Based on the adjustments for fuel and purchased power expenses, HELCO's test year filing ECA factor at current rates of 9.003 cents per kWh should be adjusted and decreased by 0.382 cents per kWh to 8.621 cents per kWh (see CA-201, Line 9).

5. Power factor adjustment charges and credits are addressed later in my testimony.

6. The Company's proposed ECAC satisfies the requirements of Act 162 considerations.

III. FUEL AND PURCHASED POWER EXPENSES.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF FUEL EXPENSE?

A. As shown in CA-201, Line 3, the Consumer Advocate recommends a test year projection of $75,188,000, which is comprised of fuel oil expense (see CA-204, Line 12) and fuel related expense (see CA-205, Line 4). CA-204 shows the derivation of the Consumer Advocate's recommended test year fuel oil expense of $74,762,200. The test year fuel related expense (i.e., $425,900 shown in CA-205) consists of propane, fuel additives and Petrospect expenses.

Q. EXPLAIN HOW YOU DETERMINED YOUR RECOMMENDED TEST YEAR FUEL EXPENSE.

A. Fuel oil expense is derived by multiplying the estimated test year fuel consumption (in barrels) at each of HELCO's generating plants by the February 2006 contract fuel prices for the type of fuel consumed at that plant (see CA-204).

To determine the test year fuel consumption at each HELCO generating plant, I first determined HELCO's total 2006 test year energy requirements as described in Section III.A. below. Next, I must determine the portion of the energy requirements that will be provided by HELCO purchases from the as-available resources. The balance of HELCO's estimated 2006 test year energy requirements, after such purchases, are assumed to be provided by HELCO's generating plants and purchases from Puna Geothermal Venture (PGV) and Hamakua Energy Partners (HEP).

To determine the amount of generation that will be produced by each of the available generating units, I simulated the economic dispatch of the available generation from HELCO, PGV, HEP, wind generation and hydro electric generation. This was done using a production simulation model.

The above resulted in the estimated test year fuel consumption of HELCO's generating units, the associated quantity of fuel that will be consumed at each of HELCO's generating plants, and the amount of test year energy purchases from PGV and HEP.

Q. WERE YOU ABLE TO USE THE RESULTS OF THE PRODUCTION SIMULATION MODEL WITHOUT FURTHER ADJUSTMENTS?

A. No, the production simulation model results needed to be adjusted to account for differences in operation that cannot be captured in the model. This adjustment is known as the calibration factor, which is used to adjust the Btu output and subsequently the amount of fuel burned at each HELCO generating plant as shown in CA-WP-204, Page 2. As described above and shown in CA-204, an estimated fuel oil price, and in CA-205 a propane price, and Fuel additive and Petrospect costs, are applied to the estimated test year fuel consumption (determined from the prior step) to arrive at the estimated 2006 test year fuel expense.

A. DETERMINATION OF THE TEST YEAR ENERGY REQUIREMENTS AND SOURCES OF ENERGY SUPPLY.

Q. HOW DID YOU DETERMINE HELCO'S ESTIMATED 2006 TEST YEAR ENERGY REQUIREMENTS?

A. The determination of HELCO's estimated 2006 test year energy requirements is set forth on CA-203, Lines 1 through 5. As shown on CA-203, the starting point of the process is the Consumer Advocate's forecasted sales for the test year. Next, the amount of energy that the Company will use at its buildings and facilities (referred to as "Company Use" and also referred to as "No Charge") is determined. Finally, the amount of energy that will be lost in the system as the power is transformed into the voltages required for transmission and distribution throughout the Company's system (referred to as HELCO system losses (8.14%)) must be determined. The sum of the above three items represents the total system energy requirements, or the amount of power that must be generated by HELCO's generation and the generation of the independent power producers who sell power to the Company.

1. The Consumer Advocate's 2006 Test Year forecasted sales for HELCO.

Q. WHAT ARE HELCO'S TEST YEAR FORECASTED SALES?

A. CA-203 contains a comparison of HELCO's sales forecast to the Consumer Advocate's sales forecast. HELCO's estimated 2006 test year energy requirements are based on a forecasted sales level of 1,148.0 GWh,

Q. WHAT IS THE CONSUMER ADVOCATE'S ESTIMATE OF HELCO FORECASTED SALES?

A. As discussed in CA-T-1, the Consumer Advocate adopted the HELCO test year sales projection.

2. The Consumer Advocate's estimated Company Use or No Charge for the 2006 test year.

Q. WHAT EXACTLY IS THIS COMPANY USE ENERGY THAT IS ADDED TO FORECASTED SALES?

A. Company Use energy involves electric energy use at HELCO's buildings and facilities. Such energy use is included with forecasted sales and system losses to determine the amount of energy to be generated by HELCO's generating units and purchased from others. Since the cost of supplying this "Company Use" is included in HELCO's revenue requirements to be recovered from ratepayers, the amount of estimated test year energy use at HELCO's buildings and facilities has an impact on the revenue deficiency and level of rate increase to be established in this proceeding.

Q. WHAT IS HELCO'S TEST YEAR ESTIMATE OF COMPANY USE OR NO CHARGE?

A. As shown in HELCO-403, HELCO included an estimate of 1,653 MWh of Company Use in its test year energy requirements.

Q. DO YOU AGREE WITH HELCO'S PROJECTED COMPANY USE OF NO CHARGE?

A. Yes. HELCO proposes to use an energy level that is 0.15% of sales in the test year. HELCO-WP-403 shows that the test year projection is slightly lower than prior experience, which indicated a level that represented 0.17% of sales in the period of 2001 through 2005. Thus, the test year company use projection is consistent with past No Charge levels.

3. Estimate of System Losses for the test year.

Q. WHAT ARE SYSTEM LOSSES AND HOW ARE THEY INCURRED BY HELCO?

A. During the transmission, distribution and transformation of electricity from HELCO's power supply resources to HELCO's customers, losses are incurred on the transmission and distribution systems. In addition, HELCO incurs step-up transformation losses for power produced at its generating facilities. The purpose of the system loss factor is to estimate the amount of energy loss that must be added to forecasted sales and Company Use to determine HELCO's total system energy requirements.

Q. PLEASE DESCRIBE THE LOSS FACTOR USED BY HELCO.

A. As shown in HELCO-403, system losses were computed at 8.14% of Net Energy to System.

Q. HOW DID HELCO PROJECT THE TOTAL SYSTEM LOSSES THAT MUST BE CONSIDERED FOR PURPOSES OF DETERMINING THE TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. The Company prepared load flow simulations to estimate generator step-up transformation, transmission and total distribution system losses. To estimate distribution system losses, HELCO interpolated and scaled the losses estimated in the HELCO 1993 System Loss Analysis to actual system losses incurred in 2006. The distribution system factors were based on a system loss analysis prepared by HELCO in 1993 to estimate the losses incurred on components of its distribution system.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY HELCO TO DETERMINE THE TEST YEAR SYSTEM LOSS PROJECTIONS?

A. No. The Company's methodology to calculate losses is reasonable. However, I recommend that the Company update its loss study (1993) and use the results of its updated study in the Company's next rate case.

4. Projected As-Available Energy for the test year.

Q. WHAT IS AS-AVAILABLE ENERGY?

A. As-available energy is that which is provided only when the resource is available. The HELCO system purchases as available energy from several run-of-river hydroelectric power plants and from wind generators.

Q. WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY AS-AVAILABLE RESOURCES?

A. HELCO estimated that the as-available resources consisting of Apollo Energy Corporation (AEC), Wailuku River Hydroelectric Power Company, Hawi Renewable Development INC (HRD), and other small hydro will provide 67.6 GWh, in the 2006 test year (see CA-212). HELCO's test year estimate of energy produced by all purchased as-available resources, except HRD was based on the five-year average of purchased energy from these producers (see HELCO-WP-404, Page 104 through 107).

The Lalamilo Wind Farm, Waiau Hydro, and Puueo Hydro facilities are owned by the Company. HELCO's test year energy estimate for the Lalamilo Wind Farm and other non-firm energy resources was provided in HELCO's response to CA-IR-458. CA-WP-204, Page 1 compares the Company's projected energy from these generating units to the energy modeled in the Consumer Advocate's production simulation. Although this comparison shows small differences in energy generated from as-available resources in the Company and Consumer Advocate models, the intent of the Consumer Advocate was to model this energy as the Company did in its model.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH HELCO'S TEST PROJECTION FOR THESE AS-AVAILABLE RESOURCES?

A. No, the Consumer Advocate reviewed the Company's response to CA-IR-458 and concluded that HELCO's estimates are supported by the five-year historical performance of these purchases. Thus, the Consumer Advocate adopted HELCO's energy estimate of as-available resources for purposes of this proceeding.

Q, WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY PGV?

A. PGV is assumed to provide HELCO 30 MW during on-peak and 27 MW during off-peak periods. To take into account PGV's forced outage rate of

7.10% on-peak and 0.63% off-peak, the production simulation dispatched PGV at a constant 27.8 MW on-peak and 26.8 MW off-peak. (See HELCO T-5, page 86, lines 11 and 12)

The Company's hourly production simulation output data, provided in HELCO's response to CA-IR-41, indicated that PGV generated 27 or 28 MW/hour on peak, and 26 or 27 MW/hour off peak. Apparently, the Company's program aggregates fractions of MWs and provides output in whole MWs, whereas the Consumer Advocate's model output provides fractions of MWs.

Thus, the difference between the generation that I modeled in my production simulation and the generation that the Company modeled was due to slight differences in hourly generation from PGV (CA-WP-204, page 1).

5. Determination of the energy to be provided by HELCO's generation and the generation from PGV and HEP.

Q. HOW ARE HELCO'S GENERATING PLANT FUEL CONSUMPTION AND ENERGY PURCHASES FROM HEP ESTIMATED FOR THE TEST YEAR?

A. HELCO's estimated fuel consumption and the estimated energy to be purchased from HEP for the test year are determined through the use of a computer production simulation model. The purpose of this model is to simulate the hour-by-hour operation of HELCO's generation system by allocating forecasted generation energy requirements among the available HELCO and HEP dispatchable generating units to determine the amount of energy to be produced by each such units to serve the balance of HELCO's energy requirements and associated costs.

The computer model economically dispatches HELCO's generating units to be loaded in order of lowest to highest incremental cost of production for each unit. The incremental cost for each unit was multiplied by its commitment penalty factor (provided by HELCO in HELCO-WP-404, Page 96) to determine the order with which the units should be dispatch. These penalty factors allow units such as Keahole CT-4 or Keahole CT-5 to be dispatched earlier than would be economical. The Company indicated that one of these units must be in operation during the period 6:00 a.m. to 9:00 p.m. to mitigate the risk of transmission line overloads. The computer model thus calculates the quantity of fuel that will be consumed by each generating unit based on the load to be carried by each unit, each unit's efficiency characteristics and the purchased power arrangements with PGV and HEP. The total consumption for each HELCO generating unit is the sum of fuel consumed for each hour of operation at that unit's hourly loading.

Q. PLEASE DESCRIBE THE COMPUTER MODEL USED BY THE CONSUMER ADVOCATE TO ESTIMATE THE QUANTITY OF TEST YEAR FUEL CONSUMPTION.

A. The computer production simulation model I have utilized is a model that has been developed within our firm to assess the reasonableness of the fuel and purchased power projections.

Q. HOW DID YOU GO ABOUT DETERMINING THE REASONABLENESS OF HELCO'S PRODUCTION SIMULATION MODEL RESULTS?

A. First, I requested generating unit and capacity and energy purchase information used by HELCO as inputs to the Company's energy dispatch production simulation model through numerous information requests.

Next, using HELCO's production simulation inputs from the Company's direct testimony filing in our firm's production simulation model, I attémpted to benchmark our production simulation model results against HELCO's own production simulation model results. The purpose of doing so was to confirm and verify that my production cost simulation model would produce similar results as presented by the Company.

Q. WERE YOU ABLE TO BENCHMARK YOUR MODEL TO HELCO'S MODEL?

A. No. I realized after receiving HELCO's hourly energy dispatch results that HELCO's input assumptions in the direct testimony and its results were not the same, as I mentioned earlier in my testimony.

Q. DO YOU HAVE ANY SUGGESTIONS FOR FUTURE RATE CASES THAT MIGHT MAKE IT EASIER TO BENCHMARK TO THE COMPANY'S MODEL?

A. Yes. I would suggest that the Company make available its production simulation model to the Consumer Advocate so that its analysts do not have to benchmark models. Rather, the analyst would focus only on the reasonableness of the Company's inputs to the simulation model and the resulting output (fuel, purchased power, etc.).

Q. GIVEN THE CHALLENGES DESCRIBED ABOVE, EXPLAIN HOW YOU INDEPENDENTLY VERIFIED THE COMPANY'S PRODUCTION SIMULATION RESULTS?

A. I focused on first independently verifying the fuel and purchased power expenses in HELCO's direct testimony filing.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR COMPARISON.

A. HELCO generating units and purchases that are considered to be base loaded units include Shipman, Hill, Puna Steam, Keahole CT-4 or CT-5, PGV, and HEP. My dispatch of PGV and HEP were essentially the same as the Company's. My production simulation resulted in greater energy from the Shipman, Hill, and Puna Steam power plants of 13,193 MWh, 14,611 MWh, and 13,902 MWh, respectively. My production simulation dispatched less energy than the Company from Keahole CT-2, Puna CT-3, and Keahole CT-4/CT-5 generating units in the amount of 7,508 MWh, 5,924 MWh, 24,800 MWh, respectively. The Company's diesel generators were dispatched slightly differently than in my model, however, in the aggregate, the total generation from the diesel generators is approximately the same in both models. My production simulation results indicate that more energy would be dispatched from the units that burn industrial fuel oil and less energy would be dispatched from the units that burn diesel fuel oil, as compared to the results of the Company's production simulation.

My production simulation resulted in a lower fuel cost for HEP than calculated by the Company's production simulation. I used the fuel component formula on page 64 of Exhibit A in the Power Purchase Agreement with HEP to independently calculate the total fuel cost based on HELCO's hourly dispatch of HEP (from HELCO's response to CA-IR-41). My independent calculation of the Company's HEP fuel cost resulted in a total fuel cost of $51,256,590. HELCO's fuel cost from HELCO-WP-545 page 3 was $51,638,500, a difference of $381,910.

Q. CAN YOU EXPLAIN WHY YOUR PRODUCTION SIMULATION DIFFERED FROM THE COMPANY'S?

A. I believe that much of the difference stems from my production simulation adhering to generating unit minimum output levels. My production simulation dispatched the base load units at higher hourly output levels than assumed in the Company's model when these units are dispatched below their minimum levels. As a consequence, higher hourly output levels resulted in a lower dispatch cost than the Company, because my model assumes the available generation is operating at a more efficient point of the heat rate curve.

In summary, I believe my economic dispatch results for the diesel generators, PGV, and HEP are comparable and reasonable. However, as stated earlier in my testimony, I believe the Company's calculation of HEP's fuel component may be $381,910 greater than it should be had it used the fuel component formula from the HEP Power Purchase Agreement. Exhibit CA-201, Line 4 shows that the Company and Consumer Advocate purchase power energy payments differ by $542,000. However, if the Company's fuel component for HEP is $381,910 less than it used in its testimony, there would only be a difference of $160,090 between the Company and the Consumer Advocate's purchase power energy payments. My results indicate that the industrial fuel oil fired units should be generating more energy than the Company's model indicates, and the combustion turbines should be generating less.

Q. WHAT HELCO INPUTS WERE REVIEWED TO ARRIVE AT THE ABOVE CONCLUSION?

A. The following are several items that are important to achieve an accurate dispatch model result: (a) generating unit minimum and maximum capacities, (b) forced outage rates, (c) generating unit maintenance schedules, (d) unit efficiency (heat rate) and (e) variable operation and maintenance costs. The results of my review of each of these items will be discussed in the following sections of my testimony.

Q. DID YOU MODIFY ANY OF THE COMPANY'S INPUTS TO THE DISPATCH MODEL?

A. Generally the inputs to my model were not modified because I wanted to independently assess the reasonableness of HELCO's dispatch results as presented in its filing. However, to ensure that my model served all of the HELCO energy requirements, I allowed five small diesel generators to dispatch below their minimum output (Kanoelehua D11, Panaewa, Ouli, Punaluu, and Kapua).

6. Need to calibrate the production model results.

Q, DOES HELCO ADJUST ITS DISPATCH MODEL RESULTS TO CALIBRATE THE RESULTS TO ACTUAL HISTORICAL COSTS?

A. Yes. HELCO applies a calibration factor to the generating unit fuel consumption.

Q. WHY DOES HELCO USE A CALIBRATION FACTOR?

A. HELCO direct testimony indicates that the calibration factor is used to adjust fuel consumption results from the production simulation modeling for actual operating conditions that cannot be completely duplicated by the computer model.

Q. HOW DOES HELCO DETERMINE THE CALIBRATION FACTORS?

A. HELCO divides the actual generating plant net heat rate for a year by the simulated net heat rate determined from the production simulation modeling results for that same year. Then the Company uses the computed calibration factor to adjust its generating plant heat rates and fuel consumption calculated by the production simulation model to be used in the fuel expense.

Q. WHY DID YOU OPPOSE THE USE OF A CALIBRATION FACTOR IN HELCO'S LAST RATE CASE (DOCKET NO. 99-0207)?

A. I opposed the use of a calibration factor in HELCO's last rate case contending that:

1. The use of a calibration factor inherently does not provide the utility with an incentive to improve the efficient operations of utility-owned generating units;
2. A calibration factor is not allowed in other jurisdictions that do not have direct pass-through fuel adders; and
3. The use of a calibration factor leads to the possible over recovery of revenues

In that proceeding, I also noted that HELCO applied a calibration factor to a 2000 test year base case that lacked historical actual operating data due to the drastically different generation mix included in the test year.

The Commission concluded that in lieu of elimination, it will allow the continued use of calibration factors, but required HELCO, on a going-forward basis, to file with the Commission and Consumer Advocate, annual reports identifying the actual system value for each year, the computer model results, and the adjustment resulting from the calibration factor. This was done to provide the Commission and the Consumer Advocate with appropriate data and information to more effectively address this issue of whether the calibration factor should continue to be used for HELCO in future rate cases.

The Commission required this information to be filed in a report by the end of January (subsequently revised to March) for the preceding calendar year, unless ordered otherwise by the Commission. (See Decision and Order No. 18365 filed February 8, 2001 in Docket No. 99-0207).

Q. HAS HELCO ANNUALLY FILED THE CALIBRATION REPORTS IN ACCORDANCE WITH THE COMMISSION'S D&O 18365?

A. Yes. The reported calibration factors are described in HELCO's direct testimony and summarized below:

Year	Calibration Factor
2000	1.027
2001	1.037
2002	1.032
2003	1.036
2004	1.038
2005	1.032

Source: HELCO T-4, Page 39

The filing of the annual calibration factor reports has provided the Commission and the Consumer Advocate with additional information and the opportunity to review HELCO's operations of its generating resources to evaluate the concerns I raised in HELCO's last rate case. I believe the required filing of annual calibration reports has lead to improvements in the determination and the future application of calibration factors. In its Direct Testimony, HELCO reports that changing from one production simulation technique to another results in the model being able to more closely replicate actual Company generation, and has led to a change in how the Company applies calibration results to test year production simulation results. As I will explain later in my testimony, this also has lead to a Company proposed change in the ECAC (which also relates to the Act 162 considerations addressed later in my testimony).

Q. WHAT CHANGE IN MODELING TECHNIQUE HAS LED HELCO TO BE ABLE TO MORE CLOSELY REPLICATE ACTUAL GENERATIONS OF ITS GENERATING SYSTEM?

A. The annual calibration results summarized above were the results of HELCO using a probabilistic modeling technique in prior rate proceeding. In the instant docket, HELCO is using a deterministic, Monte Carlo modeling technique. A good description of the probabilistic and deterministic modeling techniques and an explanation of their differences is provided in HELCO's direct testimony (see HELCO T-4, pages 40 through 42).

Essentially the difference in the modeling techniques is with the handling of unscheduled forced generating unit outages. Under the probabilistic approach, generating units are modeled at a lower capability (i.e., derated by the forced outage rate) without having to take the unit out of service to simulate forced outages. Under the deterministic Monte Carlo technique, the unit is modeled at its full capability, but the model randomly takes the unit out of service to simulate forced outage situations.

The deterministic Monte Carlo technique more closely matched HELCO's actual operations of its generation systems and resulted in a calibration factor of 1.026 for 2005 compared to the probabilistic technique, which resulted in a 2005 calibration factor of 1.032. The reasons why the deterministic Monte Carlo technique is able to more closely model HELCO's actual generation is described in HELCO's direct testimony (see HELCO T-4, pages 41 and 42), which basically is that the technique models what actually happens to a generating unit in a forced outage situation on HELCO's systems. As previously indicated, HELCO's observations of the results of the deterministic Monte Carlo modeling technique led to a change in how the Company applies calibration results to test year production modeling results.

Q. WHAT IS THE CHANGE IN HOW THE COMPANY APPLIES THE CALIBRATION RESULTS TO TEST YEAR PRODUCTION MODELING?

A. HELCO observed that the calibration results showed <u>that</u> there was a greater difference between actual and modeled results for diesel engines and combustion turbine units using diesel fuel then the difference between actual and modeled results for the steam units using industrial fuel oil ((IFO). The reasons described in HELCO's direct testimony (see HELCO T-4, page 43) seem to be that production simulation modeling more closely duplicates the operation of base-loaded units (i.e., HELCO's steam units using IFO) than it can duplicate units whose output and use can fluctuate widely (i.e., HELCO's units fueled with diesel). In recognition of the different results for steam units using IFO and diesel fueled units, HELCO calculated the following calibration factors for the two fuel types:

Fuel Type	**Calibration Factor**
IFO	1.018
Diesel	1.051
Weighted Average	1.026

Source: HELCO-WP-404, page 54

Although, a single calibration factor was used by HELCO in its last rate case filing and in HELCO's preliminary calculation of test year fuel expenses in this case, HELCO's direct testimony filing uses two calibration factors for the two fuel types (i.e., 1.018 for steam units using IFO and 1.051 for diesel fueled units) rather than a single calibration factor (i.e., 1.026 for both fuel types). In turn, as described later in my testimony, HELCO proposes to modify its ECAC to replace the single sales heat rate with two sales heat rates for the two fuel types.

Q. DID THE FILING OF ANNUAL CALIBRATION REPORTS REQUIRED BY THE COMMISSION IN THE COMPANY'S LAST RATE CASE EFFECTIVELY ADDRESS THIS ISSUE OF WHETHER THE CALIBRATION FACTOR SHOULD CONTINUE TO BE USED FOR HELCO IN THIS DOCKET AND FUTURE RATE CASES?

A. Yes. I do not have the same level of concerns regarding the use of calibration factors as I did in HELCO's last rate case, particularly in light of:

1. HELCO's use of a new modeling technique that more closely matches the model results to the Company's actual operations of its generating system;
2. HELCO's observations of the differences in calibration pertain to the two fuel types and result in separate calibration factors for the two fuel types, and HELCO's proposal to replace the system sales heat rate with two sales heat rates for each fuel type described later in my testimony; and,
3. the opportunity for the Consumer Advocate to monitor and review HELCO's operation and performance of its generation system.

Clearly the Commission's ordering of the calibration reports to be filed annually has provided the information and opportunity to effectively address this issue. The annual filing of calibration reports provides the Consumer Advocate with the opportunity to review and compare HELCO's actual operations to modeled results as one of the means to monitor whether

HELCO is efficiently generating its generating system and whether there is an over recovery of reserves as a result of the calibration factors, which effectively addressed the major concerns I raised in HELCO's last rate case. In addition, if the Consumer Advocate had access to and use of HELCO's production simulation model, the Consumer Advocate would have the ability to more effectively evaluate the Company's annual calibration reports.

I also recognize that the Commission previously ruled to allow the continued use of the calibration factors. Therefore, I recommend that the Commission continue to require HELCO, and the other utilities under its jurisdiction for that matter, to provide the same reporting requirements as required of HELCO in its last rate case in order for the Commission and the Consumer Advocate to effectively address the issue of continued use of calibration factors in future rate proceedings; and, if so, the appropriate calibration factors to be utilized for ratemaking purposes. Later in my testimony, I address how HELCO's use of two sales heat rates in the ECAC for the two fuel types addresses some of the ACT 162 considerations.

Q. DO YOU AGREE THAT THE COMPANY'S 2005 CALIBRATION FACTORS FOR THE TWO FUEL TYPES SHOULD BE USED FOR HELCO'S 2006 ESTIMATED TEST YEAR IN THIS PROCEEDING?

A. Yes. The calibration factors used in the Company's filing, however, were derived from actual 2005 data and the production simulation that was used in the Calibration Factor Annual Report for Year 2005, dated March 15, 2006. Shipman 3 and 4 are proposed to run as base load units during Test Year 2006, but were not running as base load units during all 12 months of 2005. To assess the impact that this change in Shipman 3 and 4 operations may have on the calibration factors, I prepared a sensitivity analysis of the Company's calibration factor calculations provided in HELCO-WP-404, Page 54. I scaled the actual 2005 and simulated 2005 net generated energy and fuel consumption to roughly match my production simulation results for the Test Year to adjust Shipman 3 and Shipman 4 as though those units had been in service during all of the year of 2005. My resulting calibration factors were then applied to my production simulation results on CA-WP-204, Page 2. The resulting ECAC changed approximately 0.2%. I concluded that in this instance, the Company's calibration factors are reasonable because the ECAC was relatively insensitive to the change that involved increasing Shipman 3 and Shipman 4 generated energy.

Q. WHAT ARE THE CALIBRATION FACTORS FROM 2005?

A. The calibration factors (included on CA-WP-204, Page 2) are 1.018 for Industrial Fuel Oil units and 1.051 for Diesel fuel units. These calibration factors were derived on HELCO-WP-404, Page 54.

Q. PLEASE SUMMARIZE YOUR POSITION REGARDING THE ESTIMATED TEST YEAR FUEL OIL EXPENSE.

A. My recommended test year fuel oil expense of $74,762,000 and purchased power expense of $116,776,000 are based on the February 2006 fuel oil prices provided by HELCO in its filing. Test year fuel consumption is based on my production simulation model results. My production simulation utilized HELCO's direct testimony filing input data. My fuel oil expense is less than estimated by the Company because my production simulation dispatched more industrial fuel oil and less diesel fueled generation than did the Company's Production Simulation.

B. PURCHASE POWER EXPENSE FOR THE 2006 TEST YEAR.

Q. WHAT IS PURCHASED POWER AND WHY MUST IT BE CONSIDERED IN DETERMINING THE TEST YEAR REVENUE REQUIREMENTS?

A. Over 50% of HELCO's estimated 2006 test year energy requirements is projected to be purchased from independent power producers ("IPP") at an estimated cost of $116,776,000 (see CA-201, Line 6). The amount of energy estimated to be purchased by HELCO from each IPP for the 2006 test year is summarized below:

IPP Provider	GWh Estimated to be Purchased by HELCO
PGV	221.5
HEP	421.9
Wailuku	27.5
HRD	34.2
Apollo	4.8
Other	1.0
Total	711.4

Source: CA-212

HELCO's payments to the IPPs represent a purchase power expense incurred by the Company to meet its service obligations to its customers, the ratepayers. Accordingly, HELCO's purchase power expenditures are included in HELCO's test year revenue requirements for purposes of evaluating and setting rates for the Company.

Q. HOW IS PURCHASED POWER EXPENSE DETERMINED?

A. Each IPP has a purchase power agreement ("PPA") with HELCO that sets forth the payment rates and the manner to determine the amount of HELCO's payment to the IPP. Some of the IPP providers are considered firm capacity resources in HELCO's power supply firm capacity resource planning and receive capacity payments from HELCO in addition to energy payments for the energy output of the IPP's facility that is purchased by HELCO. Other IPP providers are considered "as-available" resources and are not considered as a capacity resource and receive energy only payments. CA-211 provides the type of resource, and the amount of estimated test year energy and capacity payment, if applicable for each IPP under their PPA.

Q. DID YOU REVIEW THE CHARGES FOR PURCHASED POWER INCLUDED IN HELCO's FILING?

A. Yes. I reviewed charges associated with HELCO firm power purchases that include PGV and HEP. I also reviewed charges for as-available energy purchases from Apollo Energy Corporation (AEC), Wailuku River Hydroelectric Power Company, Hawi Renewable Development INC (HRD), Lalamilo Wind Farm, Waiau Hydro, Puueo Hydro and other small wind & hydro. In particular I reviewed the testimony of HELCO witness Dan V. Giovanni, Manager of Power Supply O&M Department (HELCO T-5).

Q. WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY PURCHASED POWER?

A. I projected that HELCO would purchase 221.5 GWh from PGV and 421.9 GWh from HEP.

Q. HOW IS THE COMPANY CHARGED FOR POWER PURCHASED FROM PGV?

A. PGV's energy payment consists of two parts, original firm capacity and additional energy. Original firm capacity is up to and including 25 MW on-peak and 22 MW off-peak. Additional energy is energy purchased above 25 MW on-peak and 22 MW off-peak. For the test year, PGV rates are based on avoided energy rates of \$0.1745/net kWh on-peak and \$0.1411/net kWh off-peak for up to 25 MW on-peak and 22 MW off-peak. Additional energy is calculated based on a fuel component and a variable O&M component. For the test year 2006, PGV additional energy rates are calculated at \$0.13032/net kWh on-peak and \$0.12032/net kWh off-peak. The fuel component is computed using a fuel rate base charge of \$0.038/kWh multiplied by a monthly fuel index. PGV's fuel index is based on the February 2006 average price as reported by Platts Los Angeles LS Diesel Pricing Report. The variable O&M component is computed using a variable O&M base charge of \$0.0029/kWh escalated annually based on changes in the Gross Domestic Product Implicit Price Deflator (GDPIPD).

Q. WHAT ARE THE ESTIMATED TEST YEAR CAPACITY AND ENERGY PAYMENTS FOR PGV?

A. The estimated test year capacity payment for PGV is \$4,256,000. The estimated test year energy payment for PGV is \$34,321,000. (See CA-211.)

Q. HOW IS THE COMPANY CHARGED FOR POWER PURCHASED FROM HEP?

A. HEP's energy payment includes two components, fuel and variable O&M. The energy charges are reduced by a two percent discount for the energy component of avoided transmission losses. The fuel component is based on HEP's guaranteed heat rate efficiency curves at HELCO's Keahole fuel cost and adjusted against fuel base price. The fuel component is calculated using the base fuel, which is the amount of kilowatts calculated at various rates by type of dispatch. The base fuel is multiplied by the Keahole monthly fuel price and divided by a fixed base factor of $4.35324 per one million British Thermal Unit. The total fuel component is adjusted to 98% (reduced by 2%). The test year composite fuel price is $88.0456 per barrel as shown on HELCO-402, page 1.

The variable O&M component is computed using the total kWh generated multiplied by a variable factor of $.00092/kWh delivered (in 1995 dollars) which is escalated annually based on changes in the GDPIPD. The overhaul component is computed using combustion turbine run hours and multiplied by an overhaul factor of $103.43/hour (in 1995 dollars), which is escalated annually based on changes in the GDPIPD. The total variable O&M is the sum of both the variable and the overhaul components adjusted to 98% (reduced by 2%).

Q. WHAT ARE THE ESTIMATED HEP TEST YEAR CAPACITY AND ENERGY PAYMENTS?

A. My estimated test year HEP capacity payment is $13,674,000 and the energy payment is $53,777,000. (See CA-211.)

Q. HOW ARE PURCHASE POWER CHARGES CALCULATED FOR THE PGV and HEP PURCHASES?

A. Purchase power charges for these purchases are calculated as illustrated in CA-211. Based on my review, these charges are consistent with the terms of the PPAs between HELCO and each IPP.

Q. DO YOU RECOMMEND ANY CHANGES TO THE HELCO DIRECT TESTIMONY PURCHASED POWER CHARGES?

A. Although I did not make any changes to the method by which HELCO computed its estimated 2006 test year purchase power expense, my recommended purchase power expense of $116,776,000 is $542,000 lower than HELCO's direct testimony filing of estimated purchase power of $117,318,000. My estimated purchased power charges are less than the Company's because I believe the Company overstated HEP fuel costs and because my production simulation dispatched slightly less energy from PGV than did the Company's.

IV. GENERATION EFFICIENCY FACTOR (SALES HEAT RATE).

Q. WHAT IS THE GENERATION EFFICIENCY FACTOR OR SALES HEAT RATE?

A. The generation efficiency factor or sales heat rate is a measure, expressed in terms of Btu per kWh or MMBtu per kWh, of the amount of fuel consumed in HELCO's generation facilities to provide a kWh of energy measured at the customer's meter. The sales heat rate is used in the Energy Cost Adjustment Clause ("ECAC") to pass through increases and decreases in the composite weighted average cost of fuel consumed at HELCO's generating plants (expressed in terms of cents per MMBtu) from that included in HELCO's base rates to HELCO's customers. Basically, the ECAC is an energy rate adjustment mechanism that passes through, after conclusion of a rate case, price changes in the Company's fuel and purchased energy cost and changes in the Company's generation and purchased energy mix from that used in arriving at the Company's test year revenue requirements and base rates in the rate case, without the need for the Company to file a new rate case. Later in my testimony I address the Act 162 considerations relating to HELCO's ECAC.

Q. PLEASE DESCRIBE THE ECAC USED BY HELCO.

A. The ECAC is a provision in the Company's rate schedule that allows HELCO to apply a factor, referred to as the Energy Cost Acquisition Factor or ECA

Factor, expressed in terms of cents per kWh, that increases or decreases ratepayer charges resulting from the Company's monthly ECAC calculations. HELCO files its ECA Factor calculations with the Commission on a monthly basis. The two major components in the monthly ECA Factor calculation are the generation factor and the purchased energy factor, both of which are expressed in terms of cents per kWh. Exhibit CA-210 provides the test year ECA Factor calculation under HELCO's current rates.

The purchased energy factor is determined as the difference between HELCO's weighted composite cost of purchased energy (computed as HELCO's average cost of purchased energy prices multiplied by the percentage of sales provided by purchased energy) and the base weighted composite cost of purchased energy embedded in HELCO's base rates. Similarly, the generation factor is the difference between HELCO's weighted composite cost of fuel prices and the base weighted composite cost embedded in HELCO's base rates. The calculation of the generation factor, however, is not as straight-forward as the purchased energy factor in that HELCO's composite fuel price of fuel consumed at the Company's generating plants is expressed in terms of cents per MMBtu, which needs to be converted to cents per kWh for the ECA Factor to be applied to HELCO's ratepayers. As previously stated, HELCO's composite purchased energy prices are already expressed in terms of cents per kWh and therefore the calculation of the purchased energy factor does not require the interim conversion step needed for determining the generation factor.

Q. HOW IS THE SALES HEAT RATE UTILIZED IN THE ECA CLAUSE?

A. The sales heat rate is utilized to convert HELCO's composite fuel prices of fuel consumed at the Company's generating plants, expressed in terms of cents per MMBtu, to a composite cost of generation, in terms of cents per kWh, for determining the generation factor. The sales heat rate is essentially a measure of HELCO's generation efficiency conversion of fuel consumed, expressed in terms of MMBtu, to electricity produced and delivered by the Company's generating units to HELCO's customers, expressed in terms of kWh. Accordingly, this generation efficiency factor or sales heat rate, expressed in terms of MMBtu per kWh, is utilized to pass through fuel price increases or decreases experienced by HELCO to the ratepayers. As a result, the sales heat rate has an impact on future customer billings.

Q. HOW IS THE SALES HEAT RATE DETERMINED?

A. The sales heat rate is determined by dividing test year fuel consumption by forecasted sales attributable to HELCO's generation (see CA-206). Test year fuel consumption is taken directly from the results of the production simulation used to determine fuel expense. The amount of forecasted sales attributable to HELCO's generation is calculated by multiplying forecasted sales by the ratio of HELCO's system generation to total (i.e., net to system) energy requirements. In other words, the calculation of HELCO's sales heat rate in this rate case proceeding will establish the fixed generation efficiency factor to be utilized in HELCO's ECAC. Thus, the sales heat rate to be implemented in HELCO's ECAC will correspond to test year resource mix utilized to determine HELCO's revenue requirements and new rates in this proceeding.

Q. WHAT EFFECT DOES THE SELECTION OF THE SALES HEAT RATE HAVE ON FUTURE CUSTOMER BILLINGS?

A. The sales heat rate implemented as a result of this proceeding will have an impact on what HELCO's customers will be charged for fluctuations in fuel prices in the future. Also, since the sales heat rate is determined by dividing fuel consumption by energy sales, the estimated Company Use energy and the estimated system loss energy discussed previously are implicitly incorporated into the sales heat rate. Accordingly, the charges to ratepayers for fluctuations in fuel prices will be based on the estimated Company Use and estimated system losses utilized to develop the sales heat rate. To the extent that the sales heat rate utilized in HELCO's ECA clause is inconsistent with test year conditions upon which rates are determined, the cost of fuel passed on to HELCO's customers will likewise not be consistent with or track the basis on which such charges for electric service were developed.

Q. WHY IS IT IMPORTANT TO DETERMINE A NORMALIZED HEAT RATE FOR RATE SETTING PURPOSES WHEN A COMPANY LIKE HELCO IS ALLOWED TO USE THE ECAC TO RECOVER THE COSTS ASSOCIATED WITH CHANGES IN THE PRICE OF FUEL OIL?

A. The sales heat rate will determine the amount to be paid by HELCO's ratepayers (in cents per kWh) when HELCO's composite generation fuel cost (in cents per MMBtu) is different than that used to set rates, and the base cost in HELCO's ECAC. If HELCO's sales heat rate is different than that used in the ECAC, the change in HELCO's fuel expense will not match dollar-for-dollar the change in HELCO's ECAC revenues. Thus, if the heat rate is overstated, HELCO will be able to recover, through the ECAC, monies that are in excess of the fuel expense incurred to meet customers' energy needs. On the other hand, if the heat rate is understated, HELCO will not be provided an opportunity to recover the fuel cost as intended through the ECAC.

Q. DID HELCO PROPOSE CHANGES TO THE EXISTING ECAC?

A. Yes. In addition to updating the ECAC for the test year base cost of fuel and purchase power, the Company is proposing two changes to the existing ECAC. First, the Company proposes to pass costs through the ECAC that are currently not passed through the existing ECAC. These costs include propane fuel costs for startup of the Shipman and Hill steam units and a Distributed Generation (DG) energy component. DG Fuel oil and related fuel transportation costs are not currently included in the ECAC, nor are propane costs.

Second, the Company proposes to essentially replace the single Central Station efficiency factor with a weighted efficiency factor determined from two fixed efficiency factors, one fixed efficiency factor for HELCO's steam units that use industrial fuel oil (IFO) and another fixed efficiency factor for HELCO's diesel fueled units (i.e., combustion turbines and diesel units). Because HELCO is proposing to replace the ECAC single fixed efficiency factor with two fixed efficiency factors for the two fuel types, a third, referred to as "other" fixed efficiency factor is then determined from the test year weighted average of the steam units using IFO fixed efficiency factor and the diesel fueled units fixed efficiency factor to apply to the Company's non-fossil fuel generating units (i.e., wind and hydro) (see HELCO-307 for HELCO's proposed ECAC, HELCO-308 for the industrial, diesel and other fixed efficiency factors and HELCO-309 for an illustration of the proposed three fixed efficiency factors).

On the other hand, while HELCO proposes to include a DG component in the ECAC for recovery of charges in DG fuel and fuel-related transportation charges, the Company is requesting that the DG units would not be subject to a fixed efficiency factor. In summary, HELCO proposes to modify the ECAC with a three-part sales heat rate (i.e., based on IFO, diesel and other fixed efficiency factors) for its steam and diesel central station units and its wind and hydro generating resources to pass through charges in central station fuel and fuel-related prices, but to use a direct pass through of charges in DG fuel and fuel-related actual expenditures (not just changes in prices) by not using a fixed efficiency factor for the DG units. The Company's direct testimony indicates that the DG unit heat rates are better than the Central Station fixed efficiency factors (see HELCO T-3, page 8). Presumably this implies that the Central Station fixed efficiency factors would be applied to the DG units rather than using a DG fixed efficiency factor.

Q. WITH RESPECT TO THE FIRST ITEM DESCRIBED ABOVE, DO YOU AGREE THAT IT IS REASONABLE TO INCLUDE PROPANE FUEL COSTS AND A DG COMPONENT IN THE ECAC AS PROPOSED BY THE COMPANY?

A. Yes. Shipman and Hill propane costs are fuel related costs that are comparable to fuel costs for other HELCO generating units that are included in the ECAC. Including a DG component in the ECAC would recover DG fuel and transportation costs and benefits from the ratepayers, although I recommend that the DG component be subject to a DG fixed efficiency factor the same as HELCO's central station units. I address this later in this section of my testimony.

Q. WITH RESPECT TO THE SECOND ITEM DESCRIBED ABOVE, FIRST DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO USE A THREE PART SALES HEAT RATE FOR HELCO'S CENTRAL STATION UNITS AND HELCO'S WIND AND HYDRO UNITS?

A. Yes. This method should cause changes in fuel prices by fuel type to track generator efficiency and generator use by fuel type more closely than a single sales heat rate. For example, prior to the test year Shipman 3 and Shipman 4 were on stand by status (i.e., held in reserve but not operated or used in HELCO's daily operations or dispatch). In the test year, however, Shipman 3 and Shipman 4 are each operated and dispatched as a two shift base load unit because the price differential between IFO and diesel fuel puts these Shipman units in the Company's economic dispatch order. In other words, although (HELCO"S diesel units have much better heat rates, (approximately 10,600 Btu/kWh) or efficiency factors than do Shipman 3 and Shipman 4 (approximately 16,500 Btu/kWh), the price differential between the IFO used to fuel the Shipman 3 and Shipman 4 units ($9.06/MMBtu) and diesel fuel (approximately $15/MMBtu) offsets the difference in heat rates to the point that the net cost of energy to the ratepayers generated by these Shipman units is economical to include in HELCO's daily generation and dispatch.

Accordingly, the Shipman 3 and Shipman 4 units are included in the test year and are included in the calculation of fixed generation efficiency factors and the sales heat rate calculations. On a going forward basis, the price differential between IFO and diesel fuels may and would, change to the point that Shipman 3 and Shipman 4 are no longer economical, at which point HELCO would likely remove theses Shipman units from its daily operation and dispatch, and place the units back on stand by status.

Under the Company's present ECAC using a single generation efficiency factor for the sales heat rate, the change in generation mix would be recognized (i.e., less energy from steam units using IFO, replaced by more energy from diesel fueled units), but the difference or change in weighted efficiency factors (i.e., recall that diesel fueled units have a better efficiency factor than HELCO's steam units using IFO), would not be recognized by the current single sales heat rate in the ECAC. The consequence is that ratepayers would be overcharged for changes in fuel prices. On the other hand, modifying the ECAC to replace the single fixed sales heat rate with one that is based on the fixed efficiency factors by type of HELCO fueled units (i.e., IFO, Diesel and other for hydro and wind) as proposed by the Company would recognize the change in efficiency factors by fuel type corresponding with the change in generation mix by fuel type.

Q. WHAT ARE YOUR RECOMMENDED CENTRAL STATION FIXED EFFICIENCY FACTORS AND HOW DO THEY COMPARE WITH THAT PROPOSED BY THE COMPANY?

A. The fixed efficiency factors that I am recommending are provided in Exhibit CA-206 and the weighted average is provided in Exhibit CA-216. A comparison of the fixed efficiency factors that I am recommending with that proposed by HELCO are provided in Exhibit CA-201 and summarized in the following tabulation:

Fixed Efficiency Factors
(MMBtu/kWh Sales)

	HELCO	**CA**	**Difference**
Sales Heat Rate - Steam	0.015640	0.015631	(0.000009)
Sales Heat Rate - Diesel	0.013627	0.013089	(0.000538)
Sales Heat Rate - Other	0.014784	0.014803	0.000019
Weighted Efficiency Factc	0.014874	0.014869	(0.000005)

Source: See CA-201

The test year sales heat rate should be 0.014869 MMBtu per kWh (see CA-201), which is less than the generation efficiency factor of 0.014874 MMBtu per kWh in HELCO's direct testimony filing. HELCO's current rates have an ECAC sales heat rate of 0.014629 that is lower than the test year projection, either the Company's proposed or the Consumer Advocate's recommended fixed sales heat rate, primarily due to the increased use of HELCO's steam units being fueled with IFO in the test year. The Consumer Advocate's fixed efficiency factors and recommended sales heat rate is based on the availability, resource mix and use of various IPP and HELCO generating resources, as described earlier in this testimony, used to develop estimated 2006 test year revenue requirements.

Q. WHAT IS YOUR POSITION REGARDING HELCO'S PROPOSAL THAT THE DG COMPONENT NOT BE SUBJECT TO A FIXED EFFICIENCY FACTOR?

A. At this time, I do not oppose HELCO's proposal that the DG units not be subject to a fixed efficiency factor. It should be noted that the whole concept of the Company's ECAC is based on the use of fixed efficiency factors being applied to HELCO's generating units to pass through changes in fuel prices to ratepayers, as opposed to a dollar pass through of fuel-related costs as proposed by HELCO for the DG component. HELCO's direct testimony relating to Act 162 considerations all speak to the merits of the ECAC's fixed efficiency factors for the appropriate risk sharing of fuel price changes between the Company and ratepayers. (see HELCO ST-22 and HELCO ST-23). The Company's DG units, however, are expected to provide only 0.01% of HELCO's energy requirements for the test year. Assuming that the requirement to annually file calibration reports continues, the Consumer Advocate and the Commission have the opportunity to monitor the DG component of the ECAC. Accordingly, HELCO's proposed DG component is acceptable to the Consumer Advocate provided that HELCO will be required to continue to annually file calibration reports with the

Commission and the Consumer Advocate. I would also like to add that if the amount of DG on HELCO's system increases, we may need to revisit this issue in the future rate cases.

V. **<u>FUEL INVENTORY</u>.**

Q. PLEASE DESCRIBE WHAT IS SET FORTH ON EXHIBIT CA-208.

A. Exhibit CA-208 provides the derivation of test-year fuel inventory amounts based on my production simulation model results and HELCO's February 2006 fuel prices. The methodology that I used for determining fuel inventory is shown in Exhibits CA-208, Pages 1 through 8 and CA-209 and is the same methodology utilized by the Company in its direct testimony filing.

Q. DID YOU REVIEW AND ASSESS HELCO'S FUEL INVENTORY CALCULATIONS?

A. Yes. HELCO maintains an inventory for Industrial Fuel Oil (IFO) that is used in HELCO's steam generating units and for diesel fuel that is used in its combustion turbines and reciprocating diesel engine generating units.

Q. WHAT DOES HELCO PROPOSE AS AN INVENTORY LEVEL FOR IFO?

A. HELCO proposes a 24-day inventory that is equivalent to an average daily IFO consumption of 2,367 barrels of IFO resulting in an inventory of 72,355 barrels of IFO (See CA-208, Page 1).

Q. DO YOU AGREE WITH THIS LEVEL OF INVENTORY?

A. No. I independently calculated IFO inventory in CA-208, Pages 1 through 3. Based on a 24-day inventory level, the number of barrels of IFO is 79,000, which is 6,645 barrels more than HELCO's filed inventory level.

Q. HOW DOES THIS INVENTORY LEVEL COMPARE TO ACTUAL HELCO INVENTORY LEVELS?

A. HELCO maintained an average IFO inventory level of 36 days from 2001 through 2005. The maximum inventory during this period was 42 days in 2004 and the minimum level was 32 days in 2001. (See CA-209, Page 1, Line 2.)

Q. WHAT DOES HELCO PROPOSE AS AN INVENTORY LEVEL FOR DIESEL FUEL OIL?

A. HELCO proposes a 30-day inventory that is equivalent to an average daily diesel consumption of 1,467 barrels of diesel resulting in an inventory of 46,796 barrels of diesel (See CA-208, Page 1, Line 8).

Q. DO YOU AGREE WITH THIS LEVEL OF INVENTORY?

A. No. I independently calculated diesel inventory in CA-208, pages 4 through 8. Based on a 30-day inventory level, the number of barrels of diesel is 29,873, which is 16,923 barrels less than HELCO's estimated test year inventory level.

Q. DO YOU AGREE WITH HELCO'S STATED GOAL OF A 24–DAY INVENTORY FOR IFO AND A 30-DAY INVENTORY LEVEL FOR DIESEL FUEL?

A. Yes. The Company explained in its filed testimony that it receives fuel deliveries on a cycle that can be as long as 19 days. However, this is not the only consideration in determining fuel oil inventory. The Company must also consider that outages of HEP and PGV could affect the amounts of fuel needed for the Company's generating units if either of the purchase power suppliers is unavailable for extended periods of time. The Company's proposal is consistent with fuel inventories maintained by other electric utilities and appears reasonable.

Q. HOW DOES THIS INVENTORY LEVEL COMPARE TO ACTUAL HELCO INVENTORY LEVELS?

A. HELCO maintained an average diesel inventory level of 45 days from 2001 through 2005. The maximum inventory during this period was 65 days in

2001 and the minimum level was 30 days in 2002. (See CA-209, Page 1, Line 4.)

Q. HOW IS THE TEST YEAR NORMALIZED FUEL INVENTORY DETERMINED?

A. As shown in Exhibit CA-208, fuel inventory is determined separately for industrial fuel oil (also referred to as "IFO") and diesel fuel. Both fuel inventories are determined by using the estimated average daily fuel burn rate in the three highest burn rate months of the year for IFO or diesel fuel oil from the production simulation model results (see Exhibit CA-208, Pages 2 through 8). The average daily burn rate, expressed in terms of number of barrels per day (bpd), is then multiplied by the desired number of days of supply (i.e., 24 or 30 days) to arrive at the average quantity of fuel to be maintained in inventory. This average fuel inventory quantity is then multiplied by test year fuel prices to arrive at the amount of fuel oil inventory to be included in rate base.

Q. WHAT WAS THE AVERAGE DAILY BURN RATE UTILIZED FOR PURPOSES OF DETERMINING RESIDUAL FUEL OIL INVENTORY?

A. HELCO estimated that its test year burn rates were 2,367 bpd for IFO (See CA-208, Page 1, Line 3). The results of my production simulation model estimated that the test year average burn rate would be 2,644 bpd for IFO.

For diesel fuel oil, HELCO estimated that its test year burn rates were 1,467 bpd for Central Station diesel and 1 bpd for distributed generators (See CA-208, Page 1, Line 8 and 9). The results of my production simulation model estimated that the test year average burn rates would be 901 bpd for Central Station diesel and 1 bpd for distributed generators.

Q. HOW MANY DAYS SUPPLY WERE UTILIZED TO DETERMINE THE QUANTITY OF IFO IN INVENTORY FOR RATEMAKING PURPOSES?

A. In its direct testimony filing, HELCO utilized a 24-day supply of fuel at the average daily burn rate in inventory for its IFO (see CA-208, Pages 2 and 3). As shown on CA-208, pages 2 and 3, I utilized the same 24-day supply of IFO inventory for purposes of determining test year fuel inventory amounts.

Q. HOW MANY DAYS SUPPLY WERE UTILIZED TO DETERMINE THE QUANTITY OF DIESEL FUEL IN INVENTORY FOR RATEMAKING PURPOSES?

A. In its direct testimony, filing HELCO utilized a 30-day supply of fuel at the average daily burn rate in inventory for its diesel fuel (see CA-208, pages 4 through 8). As shown on CA-208, pages 4 through 8, I utilized the same 30-day supply of diesel fuel inventory for purposes of determining test year fuel inventory amounts.

Q. WHAT FUEL PRICES WERE USED FOR PURPOSES OF DETERMINING TEST YEAR FUEL INVENTORY AMOUNTS?

A. I used HELCO's February 2006 fuel prices as it filed in its testimony. My review of 2006 fuel prices indicated that the Company's fuel price used in its testimony is representative of current fuel prices.

VI. <u>ECA FACTOR AT CURRENT RATES</u>.

Q. DID YOU CALCULATE WHAT THE ECA FACTOR UNDER CURRENT RATES WOULD BE FOR THE ESTIMATED 2006 TEST YEAR BASED ON YOUR ESTIMATED FUEL AND PURCHASED ENERGY PRICES AND RESOURCE MIX?

A. Yes, I did. The calculation of the ECA Factor under current rates based on my production simulation results for the estimated 2006 test year is provided as Exhibit CA-210. As shown by that exhibit, the ECA Factor at current rates that corresponds with my test year estimates of fuel and purchase power expenses is 8.621 cents per kWh (see Line 75). The ECA factor is 0.382 cents per kWh less than the ECA Factor of 9.003 cents per kWh in the Company's direct testimony filing. The difference is mostly attributable to the fuel difference in estimated resource mix.

Q. DID YOU CALCULATE ANY OTHER ECAC RELATED RATES OR CHARGES?

A. Yes. I calculated the base energy charge to be included in the ECAC at proposed rates for the Consumer Advocate's direct testimony position. Exhibit CA-217, Line 10 is the derivation of the base energy charge at proposed rates.

Q. ARE THERE ANY PROPOSED MODIFICATIONS TO HELCO'S ECAC OTHER THAN THOSE ITEMS ASSOCATED WITH UPDATES TO THE ECAC FOR THE ESTIMATED 2006 TEST YEAR AND THE TWO CHANGES PREVIOUSLY DESCRIBED IN YOUR TESTIMONY?

A. No, although there are other matters that relate to the ECAC that are associated with the Act 162 considerations that are discussed in the next section of my testimony.

VII. ACT 162 CONSIDERATIONS.

Q. HOW DOES ACT 162 AFFECT THE ECAC?

A. Act 162, in part, states the following:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
>
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
>
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;

(3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;

(4) Preserve, to the extents reasonably possible, the public utility's financial integrity; and

(5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

Q. WITH RESPECT TO THE FIRST CONSIDERATION, DOES HELCO'S PROPOSED ECAC "FAIRLY SHARE THE RISK OF FUEL COST CHANGES BETWEEN THE PUBLIC UTILITY AND ITS CUSTOMERS"?

A. The sharing of the risk of fuel cost changes first requires an understanding of how the ECAC handles fuel cost changes, and how the ECAC shares the risks of cost changes between the Company and its ratepayers. The Company's fuel costs are the result of (a) prices paid by HELCO for the quantity of fuel consumed in its generating plants, and (b) the quantity of fuel consumed is determined by the efficiency of the operation and performance of HELCO's generating units to convert the fuel into electricity delivered to ratepayers. The risks of fuel cost changes are primarily associated with the fluctuations in fuel prices (items (a) above) and to lesser extent HELCO's performance and operation of generating units (item (b) above).

As previously explained, the Company's ECAC has fixed efficiency factors to determine the amount of HELCO's fuel cost changes that are passed through to ratepayers. Essentially, the ECAC's fixed efficiency factors place on HELCO, the risk of fuel cost changes due to changes in the Company's generating unit operation and performance (item (b) above). HELCO bears the cost of, or benefits from, fuel cost changes between rate case filings due to the generation and performance of its generating units. Since the operation and performance of HELCO's generating units are generally viewed as being within the Company's control, fuel cost changes associated with such risks are considered appropriate to be borne by the Company and its shareholders, not ratepayers. If the Company's generating system does not achieve the level of efficiency established in the last rate case and used to set HELCO's rates, the Company and its shareholders bear the risk and associated fuel costs of not achieving that level of efficiency. On the other hand, if HELCO's generating units do better than the efficiency level established in the last rate case, the Company and its shareholders receive the benefits of such fuel cost savings. The ECAC's fixed efficiency factors are thus an effective means of sharing the operating and performance risks between HELCO's ratepayers and shareholders.

With respect to the risk of fuel cost changes due to changes in fuel prices, the ECAC passes such risks in price changes through to ratepayers. Because fuel prices are not within HELCO's control and HELCO is a price taker, it is not considered appropriate for HELCO to bear the risks of fuel cost changes due to price changes established by a global market. The question then becomes whether there should be some incentive or risk sharing regarding decisions as to when and how much fuel should be purchased at the prices established by a global market. It is not clear to me that the Company has a fuel purchasing plan or strategy in place that is approved and maintained by the Commission to measure the Company's actions and decisions relating to fuel prices.

Q, SHOULD THE COMPANY BEAR ANY RISK OF FUEL PRICES?

A. The Company should be required to prove that it has taken appropriate actions to acquire fuel at reasonable costs. This could be done through a process, which requires the Company to periodically file a fuel plan with the Commission. The purpose of the plan would be to assume that the Company is taking appropriate measures to acquire fuel at the lowest cost possible on behalf of its customers.

Q. DOES THE COMPANY'S ECAC "PROVIDE THE PUBLIC UTILITY WITH SUFFICIENT INCENTIVES TO REASONABLY MANAGE OR LOWER IT FUEL COSTS AND ENCOURAGE GREATER USE OF RENEWABLE ENERGY?"

A. As previously indicated, the Company's fuel costs is function of (a) fuel prices and (b) the efficiency of the Company's operation and performance of its generating units. The ECAC's fixed efficiency factors are effectively an incentive in place for HELCO's generating unit operations and performance. Fuel costs changes due to changes in fuel prices are passed through the ECAC to ratepayers and it is not clear to me what Company incentives are in place relating to fuel prices. As previously indicated, fuel prices are not within the Company's control and therefore are not manageable by the Company. However, as I stated previously, the Company should at least be required to periodically indicate its plan to acquire fuel at the lowest cost possible on behalf of its customers. This plan should indicate what actions the Company has taken to acquire fuel other than to just pay an indexed price under a long term contract.

With regard to renewables, the ECAC provides HELCO with the opportunity to recover or pass through to ratepayers the Company's purchased energy costs for generation provided by independent producers of renewable energy. Accordingly, there is not a ratemaking or ECAC preference to HELCO favoring the recovery of the Company's fuel cost for its own generation over the purchased energy cost of renewables. It is not clear to me why or how the ECAC should be modified to encourage greater use of renewable energy. A working IRP process is where the decisions should be made regarding the balance of reliable resource diversity, implementation of State energy policy and compliance with renewable resource portfolio standards at the lowest reasonable cost, rather than using the ECAC.

The ECAC essentially should be the risk sharing pass through mechanism for the Company's fuel costs and purchased energy costs (including energy provided by renewable resources) resulting from the implementation of the Company's IRP plan. It is not clear to me how the ECAC can be used to encourage greater use of renewables without either imposing penalties on HELCO or increasing costs to ratepayers. An evaluation or a determination of whether such punitive measures to the Company and/or ratepayers could reasonably be expected to have the desired effect (i.e., encourage greater use of renewable resources) and that it would be worth the punitive affect borne by HELCO and/or ratepayers. Such an evaluation or determination of whether the Company is reasonably considering renewable resource options to meet the customer's energy needs, and whether penalties should be assessed for non-performance should be done in the context of the IRP process.

Q. DOES THE COMPANY'S ECAC "ALLOW THE PUBLIC UTILITY TO MITIGATE THE RISK OF SUDDEN OR FREQUENT FUEL COST CHANGES THAT CANNOT OTHERWISE REASONABLY BE MITIGATED THROUGH OTHER COMMERCIALLY AVAILABLE MEANS, SUCH AS THROUGH FUEL HEDGING CONTRACTS?"

A. The Company's direct testimony points out that hedging, either by physical means or financial instructions, provides a means for locking in a known price at a added cost that should be passed on to ratepayers (see HELCO S-23, pages 18 and 19, and HELCO S-24, page 4). HELCO proposes budget billing and fix payment plans as alternatives to ratepayers for smoothing fuel cost changes (see HELCO s-23, page 20 and 21). If the Company cannot achieve non-volatile fuel prices through its fuel purchasing plan, it would seem reasonable that customers who desire less fluctuation in their electric charges from month to month would have the option of levelizing their payments through budget billing that would not charge the customer more than it otherwise would pay over a period of one year.

Q. WITH RESPECT TO THE FOURTH ITEM "PRESERVE, TO THE EXTENT REASONABLY POSSIBLE, THE PUBLIC UTILITY'S FINANCIAL INTEGRITY AND THE FIFTH ITEM "MINIMIZE, TO THE EXTENT REASONABLY POSSIBLE, THE PUBLIC UTILITY'S NEED TO APPLY FOR FREQUENT APPLICATIONS FOR GENERAL RATE INCREASES TO ACCOUNT FOR THE CHANGES TO ITS FUEL COSTS," IS THE COMPANY'S ECAC APPROPRIATE FOR CONSIDERATION OF THESE MATTERS?

A. I do not believe there is any question that an ECAC is needed to preserve the Company's financial integrity. As noted in the Company's direct testimony, even looking at the HEI companies on a consolidated basis (i.e., HECO, MECO and HELCO), fuel and purchased power expenditures represented nearly 67% of expenses in 2005, and the portion of fuel and purchase power expenses to total expenses rose steadily between 2002 and 2005. We are all aware that oil prices have risen substantially during this time period.

HELCO should be provided a reasonable opportunity to recover the fuel cost and purchased energy expenses incurred with providing electric service to ratepayers. HELCO's ECAC provides a means for the Company to pass through to ratepayers the changes in fuel and purchased energy costs, as such changes occur, between rate case filings. Absent such an ECAC, the Company would need to have more frequent rate case filings during periods of rising fuel prices. This would be necessary to recover the increased cost of fuel and purchased energy to maintain the financial integrity of the Company. Even so, the time that it takes to prepare, fully consider and prosecute a rate case filing would put some additional financial risk exposure on the Company. On the flip side, during periods of falling fuel prices the Company would experience a windfall, absent an Order to Show Cause why the rates should not be reduced to recognize the lower fuel costs and the Commission and the Consumer Advocate would be hard pressed to monitor the Company's financial situation and find a method to provide rate relief for ratepayers. In either situation, the administrative burdens on the Company, the Commission and the Consumer Advocate are avoided with the Company's ECAC.

Q. WHAT CONCLUSIONS SHOULD BE REACHED WITH RESPECT TO THE ACT 162 CONSIDERATIONS OF THE COMPANY'S ECAC?

A. The Company's ECAC provides a fair sharing of the risks of fuel costs changes between the Company and its ratepayers in a manner that preserves the financial integrity of the Company without the need for frequent rate filings.

VIII. POWER FACTOR.

Q. DID YOU REVIEW HELCO's POWER FACTOR ADJUSTMENT IN ITS RETAIL RATE SCHEDULES?

A. Yes. At the direction of the Consumer Advocate, I reviewed the Power Factor Clause included in HELCO rate schedules:

- J – General Service
- P – Large Power Service
- U – Time-Of-Use Service
- TOU-J – Commercial Time-Of-Use-Service
- TOU-P – Large Power Time-Of-Use Service

Exhibit CA-218 titled "Power Factor – The Basics" is a presentation that I've used in the past to explain power factor and the need for power factor provisions in a utility's rate schedules. Although the concept is often difficult to understand, power factor, in summary, is a measure of the customer's reactive power needed to operate the customer inductive loads such as induction motors, certain types of lighting and transformers. Also, there are devices and equipment, such as capacitors that the customer can install to balance out its reactive power needs rather than the utility providing the reactive power to the customer. In fact, almost without exception, the best location to deal with reactive power is at the source; i.e., the customer's equipment creating the need for reactive power. The consequence of the utility supplying the customer's reactive power (rather than the customer installing the equipment to do so itself) is higher utility system losses, installation of capacitor banks and the need for more capacity for the system to produce and deliver the reactive power needs of the customer.

Q. HOW IS THE POWER FACTOR USED IN THESE RATE SCHEDULES?

A. The energy and demand charges in each of the J and TOU-J rate schedules mentioned previously are decreased or increased by 0.10% for each 1% that the average monthly power factor is above or below 85% and the P, U and TOU-P rate schedules are decreased or increased by 0.10% for each 1% that the average monthly power factor is above or below 85%.

Q. DO YOU BELIEVE THIS METHOD OF CALCULATION IS REASONABLE?

A. I believe that adjusting the demand and energy charges to reflect the customer's power factor is appropriate. However, it is not a common practice to decrease the customer's charges if a certain power factor is achieved.

Q. WHAT IS A COMMON PRACTICE OF APPLYING ADJUSTMENTS FOR POWER FACTOR?

A. A common electric utility industry practice is to charge the customer when its power factor is less than a particular power factor such as 95% lagging.

Q. WHY IS A 95% POWER FACTOR REASONABLE?

A. The electric power system must operate at a 100% power factor. Electric generators provide the reactive power that is consumed by customers. Power factor is the measure of reactive power consumed in relation to real power consumed by the customer. The lower the consumer power factor, the greater amount of reactive power that must be supplied by the electric utility.

Q. WHAT IS A REASONABLE POWER FACTOR FOR THE UTILITY TO SUPPLY?

A. Prudent utility practice is for the electric utility to correct power factor from 95% to 100% using electric generation.

Q. WHAT DO YOU RECOMMEND THAT HELCO SHOULD MODIFY IN ITS RATE SCHEDULES?

A. I recommend that HELCO increase the customer charges when power factor is less than 95% lagging and that no credits would apply to the customer's charges with regard to power factor.

Q. DO YOU RECOMMEND A PARTICULAR RATE ADJUSTMENT?

A. In the absence of cost of service information specific to power factor, it would be reasonable to increase demand and energy charges to customers 0.1% for each percent that the customer's power factor is less than 95% power factor. This 0.1% adjustment for each percent of power factor less than 95% is the same adjustment as is currently used by HELCO. However, the specific adjustment provision should be determined from a cost of service study that calculates the cost of reactive power and subsequently translates that cost into a power factor adjustment.

IX. CONCLUSION.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

JOSEPH A. HERZ

Mr. Herz has over 30 years of experience in the areas of public utility planning, financing, operations and management for electric, natural gas, steam, water and wastewater utilities.

He is a registered Professional Engineer. His professional experience includes planning and analytical studies related to electric power supply, transmission arrangements, feasibility studies, economic analyses and rate studies and contract negotiations. He has conducted detailed cost-of-service, rate, financial, power supply and transmission studies involving various investor, municipal and cooperative-owned systems.

Mr. Herz has testified on numerous occasions as an expert witness concerning regulatory matters. He has participated in more than 100 regulatory proceedings and has testified before 14 state regulatory commissions and the FERC on electric, gas, steam and water utility services.

He is experienced in long-range planning for acquisition and/or expansion of utility systems, engineering, financial and economic feasibility investigations and analyses. Power supply experience includes evaluating the technical and financial feasibility of transmission and power supply resources and related arrangements; power pooling, including integration of transmission and generating facilities; and, preparation and negotiation of related power supply and transmission contracts. Mr. Herz has served as an independent arbitrator on power supply contract disputes.

Education

University of Nebraska
B.S., Electrical Engineering, 1971

Registration

Professional Engineer — Indiana and Ohio

Professional Organizations

American Gas Association
American Public Power Association
American Water Works Association
The Institute of Electrical and Electronics Engineers, Inc.
National Society of Professional Engineers
Ohio Society of Professional Engineers

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Utility	Docket No.	Issues and/or Scope	Client	Year
Federal Energy Regulatory Commission				
Westar Energy, Inc.	ER05-925-000	Open Access Transmission Tariff rate revisions for transmission and ancillary services	Kansas Municipal Utilities. Kansas Power Pool, Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities and Kansas Municipal Energy Agency	2005
Westar Energy, Inc. Kansas Gas and Electric Company	ER03-9-002, -003, -004, -005 ER98-2157-002, -003, -004 EL05-64-000	Westar Energy and KGE market power mitigation proposal	Kansas Municipal Utilities and Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities	2005
Kansas City Power & Light Company and Great Plains Power, Inc.	ER99-1005-000 ER02-725-000 EL05-3-000	Ability of KCP&L to exercise market power	Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities	2005
Dayton Power & Light Company	EL00-24-000	Contract dispute and interpretation of certain pricing provisions	Arcanum, Eldorado, Jackson Center, Lakeview, Mendon, Minster, New Bremen, Tipp City, Waynesfield and Yellow Springs, Ohio	2000
Western Resources and Kansas City Power & Light	EC97-56-000	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
Western Resources and Kansas City Power & Light	ER97-4669-000	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
FirstEnergy Operating Companies	EC97-5-000	IEU/FirstEnergy Merger Intervention and other related relief	Industrial Energy Users of Ohio	1997
FirstEnergy Operating Companies	EC97-413-000	IEU/FirstEnergy Merger Intervention and other related relief	Industrial Energy Users of Ohio	1997

PROJECTS INVOLVING REGULATORY FILINGS
Joseph A. Herz, P.E.

Public Utility District No. 2 of Grant County Washington	EL95-35-000	Determine appropriate allocation of power from Priest Rapids Project	Kootenai Electric Cooperative, Inc., Clearwater Power Company, Idaho County Light & Power Cooperative Association, Inc., and Northern Lights, Inc.	1995
PacifiCorp	ER96-8-000	Transmission, cost of service and rate design	Utah Municipal Power Agency Deseret Generation and Transmission Cooperative, Inc.	1995
Dayton Power & Light Company	ER95-83-000	Transmission power services and rates	Arcanum, Eldorado, Jackson Center, Lakeview, Mendon, Minster, New Bremen, Tipp City, Waynesfield and Yellow Springs, Ohio	1995
Dayton Power & Light Company	94-1469-000	Transmission/interconnection/power services and rates	City of Piqua, Ohio	1994
Cincinnati Gas & Electric Company	ER94-1637-000	Transmission service and rates	City of Hamilton, Ohio	1994
Public Service Company of New Mexico	EL-94-6-000	Fuel inventory practices and expense accounting	Plains Electric Generation and Transmission Cooperative	1994
CINergy (merger of Cincinnati Gas & Electric Company and PSI Energy, Inc.)	ER93-6-000	Transmission issues, cost of service and rate design	City of Hamilton, Ohio	1993
American Electric Power Company	ER93-540-000	Transmission issues, cost of service and rate design	City of Hamilton, Ohio	1993
Ohio Power Company and Kentucky Power Company	ER93-295-001	Transmission loss factors	City of Hamilton, Ohio	1993
PacifiCorp Electric Operations	ER93-675-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1993

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

PacifiCorp Electric Operations	ER91-494-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1991
PacifiCorp Electric Operations	ER91-471-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1991
Ohio Power Company	EL91-1-000 and EL90-42-000	Interconnected utility operations and scheduling matters	City of Hamilton, Ohio	1990
Arizona Public Service Company	ER89-265-000	Transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1989
Cincinnati Gas & Electric Company	ER89-17-000 and ER89-19-000	Transmission service, schedule restrictions and billing for transmission service	City of Hamilton, Ohio	1989
Utah Power and Light Company	EL85-12	PURPA wheeling under Sections 210, 211 and 212 of the Federal Power Act	Utah Municipal Power Agency and City of Manti, Utah	1985
Utah Power and Light Company	ER84-571/572	Transmission issues, cost of service and rate design	Utah Municipal Power Agency and the Cities of Manti and Provo, Utah	1985
Northern Indiana Public Service Company	ER83-396-000	Transmission issues, price squeeze, cost of service and rate design	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Walkerton and Winamac, Indiana	1983
Utah Power and Light Company	ER83-427-000	Transmission issues, revenue requirement, cost of service and rate design	Manti, Utah	1983
Ohio Power Company	ER82-553-000	Engineering issues, cost of service and rate design	Ohio Power Municipals	1982
Arizona Public Service Company	ER82-481-000	Transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1982
Arizona Public Service Company	ER81-179-000	Wholesale and transmission issues,	Plains Electric Generation and	1981

		cost of service and rate design	Transmission Cooperative	
Public Service Company of New Mexico	ER80-313	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Public Service Company of New Mexico	ER79-478/479	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Public Service Company of New Mexico	ER78-337/338	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Northern Indiana Public Service Company	ER78-509	Price squeeze and rate design	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Walkerton and Winamac, Indiana	1979
Federal Power Commission:				
Ohio Edison Company	E-9497	Engineering issues, cost of service	The Wholesale Consumers of Ohio Edison Company	1976
Colorado Public Utilities Commission:				
Public Service Company of Colorado	1425 Phase II	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Florida Public Service Commission:				
Florida Power Corporation	80119-EU	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Gulf Power	010949-EI	Engineering and cost of service issues that have an actual or potential impact on the FEA	The Executive Agencies of the United States	2001
Hawaii Public Utilities Commission:				

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Hawaiian Electric Company, Inc.	05-0145	HECO CIP Project Application	Division of Consumer Advocacy, State of Hawaii	2006
Hawaiian Electric Company, Inc.	7310	HECO Utilities Avoided Cost Investigation	Division of Consumer Advocacy, State of Hawaii	2005
Hawaiian Electric Company, Inc.	04-0113	Evaluation of application for an increase in rates using a 2005 test year, cost of service and rate design issues	Division of Consumer Advocacy, State of Hawaii	2004
Commission Initiated Generic Investigation	03-0371	Commission initiated generic investigation of distributed generation in Hawaii	Division of Consumer Advocacy, State of Hawaii	2004
Kauai Electric Division	01-0005	Avoided energy costs associated with an Energy Purchase Agreement with Kauai Winds Inc. and inclusion in ERAC	Division of Consumer Advocacy, State of Hawaii	2001
Hawaii Electric Light Company, Inc.	99-0355	Transmission system improvements with IPP purchase power addition	Division of Consumer Advocacy, State of Hawaii	2000
Hawaii Electric Light Company, Inc.	99-0207	Generation and purchase power, operation and maintenance expenses, system losses and engineering issues	Division of Consumer Advocacy, State of Hawaii	2000
Hawaii Electric Light Company, Inc.	99-0346	Need for capacity additions/review of IPP Purchase Power Agreement	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc.	98-0013	Need for capacity resource additions, IPP purchase power agreement	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc	97-0420	Generation and purchase power, operation and maintenance expenses, system losses and engineering issues	Division of Consumer Advocacy, State of Hawaii	1999

Hawaii Electric Light Company, Inc	97-0349	Integrated resource planning	Division of Consumer Advocacy, State of Hawaii	1999
Kauai Electric Division	KE94-0097	Engineering issues, generation and purchase power, operation and maintenance expenses, system losses and cost of service and rate design	Division of Consumer Advocacy, State of Hawaii	1994
Hawaiian Electric Company, Inc.	7766	Engineering issues, generation and purchase power, operation and maintenance expenses, system losses and cost of service and rate design	Division of Consumer Advocacy, State of Hawaii	1994
Hawaii Electric Light Company, Inc.	7623	Need for capacity resource additions and purchase power contracts	Division of Consumer Advocacy, State of Hawaii	1994
Hawaii Electric Light Company, Inc.	7764	Engineering issues, generation and purchase power, operation and maintenance expenses and system losses	Division of Consumer Advocacy, State of Hawaii	1994
Indiana Public Service Commission				
Wayne County Rural Electric Membership Cooperative	39048	Engineering issues, cost of service and rate design	Wayne County Rural Electric Membership Cooperative	1990
New Carlisle, Indiana	Unknown	Engineering issues, revenue requirements, cost of service and rate design	New Carlisle, Indiana	1975
Kansas Corporation Commission:				
Southwest Power Pool, Inc.	06-SPP-202-COC	Application for the limited purpose of managing and coordinating the use of certain transmission facilities located within the State of Kansas	Kansas Municipal Utilities, Inc. Kansas Municipal Electric Agency Kansas Corporation Commission Kansas Public Power	2006

Westar Energy, Inc. Kansas Gas and Electric Company The Empire District Electric Company Kansas City Power & Light Company Aquila, Inc. D/B/A Aquila Networks-WPK Midwest Energy, Inc. Southwestern Public Service Company	06-WSEE-203-MIS	Joint Application for authority to transfer functional control of certain transmission facilities to the Southwest Power Pool, Inc.	Kansas Municipal Utilities, Inc. Kansas Municipal Electric Agency Kansas Corporation Commission Kansas Public Power	2006
Western Resources and Kansas City Power & Light	97-WSRE-676-MER	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
Kansas Gas and Electric Company	142-098-U	Engineering issues, cost of service and rate design	McConnell Air Force Base	1985
Michigan Public Service Commission:				
Detroit Thermal	Case No. U-13691	Implement initial default tariff rates for steam service	Detroit Thermal	2004
Michigan Consolidated Gas Company	Case No. U-7895	Engineering issues, cost of service and rate design	Traverse City Light and Power Board	1984
Indiana and Michigan Electric Company	Case No. U-7791	Engineering issues, cost of service and rate design	Auto Specialties, Southern Michigan Cold Storage, Watervliet Paper Company, and Whirlpool Corporation	1984
Detroit Edison Company	Case No. U-7232	Interconnection agreements and power sales contract	Michigan Attorney General	1983
Consumers Power Company	Case No. U-6923	Cost of service, rate design and price	Clark Equipment Company	1982

		elasticity		
Indiana and Michigan Electric Company	Case No. U-6927	Engineering issues, cost of service and rate design	Auto Specialties, Clark Equipment Company, and Whirlpool Corporation	1981
Upper Peninsula Power Company	Case No. U-6785	Engineering issues, cost of service and rate design	Michigan Technological University	1981
Upper Peninsula Power Company	Case No. U-6485	Engineering issues, cost of service and rate design	Michigan Technological University	1980
Indiana and Michigan Electric Company	Case No. U-6148	Engineering issues, cost of service and rate design	Auto Specialties, Clark Equipment Company, and Whirlpool Corporation	1980
Missouri Public Service Commission:				
Kansas City Power and Light Company	ER-2006-0314	Rate Design and special rates for space heating.	The Trigen Companies	2006
Kansas City Power and Light Company	Case No. ER83-49	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Kansas City Power and Light Company	Case No. EO-78-161	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Montana Public Service Commission:				
Malmstrom Air Force Base	D2001.10.144	Rate design for customers receiving default power supply and transmission services, and limitations on the ability of qualified customers to return to the default supply services	The Executive Agencies of the United States	2001
New Mexico Service Commission:				

Joseph A. Herz, P.E.

Public Service Company Of New Mexico	Case No. 03-00352-UT	Appropriateness of underground projects Rate Rider	Rio Rancho, New Mexico	2004
Otero Electric Cooperative	Case No. 2048	Demand metering and rate design	Otero Electric Cooperative	1987
Gas Company of New Mexico	Case No. 1875	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1984
Gas Company of New Mexico	Case No. 1787	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Gas Company of New Mexico	Case No. 1710	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1982
Gas Company of New Mexico	Case No. 1568	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1982
Ohio Public Utilities Commission:				
FirstEnergy Operating Companies	Case No. 98-1636-EL-UNC	Transmission system reliability - sale and transfer of generating assets	Industrial Energy Users of Ohio	1999
Ohio Edison Company	Case No. 93-1048-EL-CSS	Cost of service and predatory pricing	Youngstown Thermal, Limited Partnership	1994
Cincinnati Gas & Electric Company	Case No. 87-593-GA-CSS	Metering and billing dispute	Sheraton/Springdale Hotel	1987
Dayton Power and Light Company	Case No. 82-517-EL-AIR	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Dayton Power and Light Company	Case No. 81-1256-EL-AIR	Revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1982
Dayton Power and Light Company	Case No. 81-1237-EL-CSS	Billing procedures and practices	The Dayton Tire and Rubber Company	1982

Toledo Edison Company	Case No. 81-620-EL-AIR	Determination of billing units and rate design	Seaway Food Town, Inc.	1982
Ohio American Water Company	Case Nos. 81-385-WW-AIR and 81-739-WW-CMR	Engineering issues, cost of service and rate design	City of Tiffin, Ohio	1982
Dayton Power and Light Company	Case No. 81-21-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1981
Dayton Power and Light Company	Case No. 80-687-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1981
Ohio American Water Company	Case No. 79-3143-WW-AIR	Engineering issues, revenue requirements, cost of service and rate design	Cities of Marion and Tiffin, Ohio	1980
Dayton Power and Light Company	Case No. 79-510-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1980
Cincinnati Gas & Electric Company	Case No. 79-11-EL-AIR	Cost of service and rate design	The Ohio Council of Retail Merchants	1979
Columbus and Southern Ohio Electric Company	Case No. 78-1438-EL-AIR	Cost of service and rate design	The Ohio Council of Retail Merchants	1979
Seneca Utilities, Inc.	Case No. 78-287-WW-AIR	Engineering issues, revenue requirements, cost of service and rate design	Lake Seneca Property Owners Association	1979
Dayton Power and Light Company	Case No. 78-92-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1979

Texas Public Utility

PROJECTS INVOLVING REGULATORY FILINGS

Joseph A. Herz, P.E.

Commission:				
Houston Lighting & Power Company	5779	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1984
Utah Public Service Commission:				
Hill Air Force Base	01-035-01	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-23	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-35	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-36	Evaluate power cost adjustment mechanism to determine if it is non-discriminatory, accurately reflects the actual cost of providing the service, and is necessary under the circumstances	The Executive Agencies of the United States	2001
Hill Air Force Base	00-035-15	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Wisconsin Public Service Commission:				
Barron Electric Cooperative	Case No. 380-EI-1	Transmission wheeling charges	Barron Electric Cooperative	1982
Wyoming Public Service Commission:				
PacifiCorp	20000-ER-95-99	Revenue requirements, cost of service, rate design and jurisdictional allocations	Marathon Oil Company	1996

Hawaiian Electric Light Company, Inc.

COMPARISON OF TEST YEAR ESTIMATES FOR FUEL EXPENSE, PURCHASE POWER EXPENSE, EFFICIENCY FACTOR (SALES HEAT RATE) AND FUEL INVENTORY

Line	Description	CA Reference	Units	Production Simulation Results using HELCO DT Inputs: HELCO DT Filing	Production Simulation Results using HELCO DT Inputs: CA Output Results	CA DT Position	CA Adjustments to HECO DT Filing (c -a)
				(a)	(b)	(c)	(d)
	FUEL EXPENSE						
1.	Fuel Oil Expense	CA-204, Line 12	$000s	$ 78,400	$ 74,762	$ 74,762	$ (3,638)
2.	Fuel Related Expense	CA-205, Line 4	$000s	$ 425	$ 426	$ 426	$ 1
3.	Total Fuel Expense		$000s	$ 78,825	$ 75,188	$ 75,188	$ (3,637)
	PURCHASED POWER EXPENSE						
4.	Energy Payments	CA-211, Line 7	$000s	$ 99,388	$ 98,846	$ 98,846	$ (542)
5.	Firm Capacity Payments	CA-211, Line 7	$000s	$ 17,930	$ 17,930	$ 17,930	$ 0
6.	Total Purchased Power Expense		$000s	$ 117,318	$ 116,776	$ 116,776	$ (542)
	FIXED EFFICIENCY FACTORS						
7.	Sales Heat Rate - Steam	CA-206, Line 18	MMBTU/kWh Sales	0.015640	0.015631	0.015631	(0.000009)
	Sales Heat Rate - Diesel	CA-206, Line 19	MMBTU/kWh Sales	0.013627	0.013089	0.013089	(0.000538)
	Sales Heat Rate - Other	CA-206, Line 20	MMBTU/kWh Sales	0.014784	0.014803	0.014803	0.000019
	WEIGHTED EFFICIENCY FACTOR	CA-216, Line 3	MMBTU/kWh Sales	0.014874	0.014869	0.014869	(0.000005)
8.	FUEL INVENTORY	CA-208, Page 1, Line 10	$000s	$ 8,266	$ 7,161	$ 7,161	$ (1,105)
	ENERGY COST ADJUSTMENT CLAUSE						
9.	ECA Factor at Current Rates	CA-210, Line 75	¢/kWh	9.003	8.621	8.621	(0.382)
10.	Base Fuel Energy Charge at Proposed Rates	CA-217, Line 10	¢/kWh	16.0249	15.6089	15.6089	(0.4160)

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL OIL PRICES

Direct Testimony

Line		HELCO DT Delivered-to-plant Weighted Fuel Price ($/BBL)	CA DT Delivered-to-plant Weighted Fuel Price ($/BBL)
1	Shipman (IFO)	57.0902	57.0902
2	Hill (IFO)	57.0902	57.0902
3	Puna (IFO)	58.3389	58.3389
4	Waimea (Diesel)	87.7341	87.7341
5	Kanoelehua (Diesel)	86.7252	86.7252
6	Keahole (Diesel)	88.0456	88.0456
7	Puna CT-3 (Diesel)	86.7656	86.7656
8	Distributed Generators (Diesel)	94.0338	94.0338

CA Reference:
HELCO-402

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 NET GENERATION
Direct Testimony

Line		HELCO DT (A) Energy (GWH)	HELCO DT (B) Percent of Net System Input	CA DT (C) Energy (GWH)	CA DT (D) Percent of Net System Input
1	Test Year Sales	1,148.0		1,148.0	
2	+ No Charge (@ 1653 MWH)	1.7		1.7	
3	Sales + No Charge	1,149.7		1,149.7	
4	+ Losses (@ 8.14%)	101.8		101.8	
5	Net-To-System Input	1,251.4	100.00%	1,251.4	100.00%
6	- Purchase Power	710.1	56.74%	711.0	56.81%
7	Net HELCO	541.3	43.26%	540.4	43.19%
7a	Central Station	514.5	41.12%	513.6	41.05%
7b	Distributed Generators	0.1	0.01%	0.1	0.01%
7c	Wind/Hydro	26.7	2.13%	26.7	2.13%

CA Reference:
Line 1: HELCO-403
Line 2: HELCO-403
Line 4: HELCO-403
Line 6: CA-WP-204, page 2
Line 7a: CA-WP-204, page 2
Line 7b: CA-WP-204, page 2
Line 7c: CA-WP-204, page 2

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL OIL EXPENSE SUMMARY
Direct Testimony

		HELCO DT			CA DT		
Line	Plant	(A) Fuel Consumption (BBLs)	(B) Fuel Prices ($/BBL)	(C) = (A) x (B) Fuel Expense ($000)	(D) Fuel Consumption (BBLs)	(E) Fuel Prices ($/BBL)	(F) = (D) x (E) Fuel Expense ($000)
1	Shipman	95,749	57.0902	5,466.3	129,439	57.0902	7,389.7
2	Hill	432,386	57.0902	24,685.0	462,771	57.0902	26,419.7
3	Puna	197,482	58.3389	11,520.9	227,934	58.3389	13,297.4
4	IFO Subtotal	725,617		41,672.2	820,144		47,106.8
5	Waimea	1,241	87.7341	108.9	1,131	87.7341	99.2
6	Kanoelehua	7,121	86.7252	617.6	8,285	86.7252	718.5
7	Keahole	354,836	88.0456	31,241.7	270,709	88.0456	23,834.8
8	Puna CT3	54,629	86.7656	4,739.9	34,294	86.7656	2,975.5
9	Diesel Subtotal	417,827		36,708.1	314,419		27,628.0
10	Central Station Total	1,143,444		78,380.3	1,134,563		74,734.8
11	Distributed Generators	213	94.0338	20.0	291	94.0338	27.3
12	GRAND TOTAL	1,143,657		78,400.3	1,134,854		74,762.2

CA Reference:
Column D: CA-WP-204, page 2
Column E: CA-202
Column F: Column D x Column E

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL RELATED EXPENSES
($000)
Direct Testimony

Line		HELCO DT Dollars ($000)	CA DT Dollars ($000)
1	Propane Expenses	232.2	233.3
2	Fuel Additives Expenses	121.3	121.3
3	Petrospect Expenses	71.3	71.3
4	Total	424.7	425.9

CA Reference:
Line 1: From Power Supply Dispatch Model
Line 2: HELCO-405
Line 3: HELCO-405

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL EFFICIENCY
Direct Testimony

Line			HELCO DT	CA DT
1	Cental Station Generated Energy	(Net GWH)	514.5	513.6
2	Steam Generated Energy	(Net GWH)	318.6	360.3
3	Diesel Generated Energy	(Net GWH)	195.9	153.4
4	Test Year Sales	(GWH)	1,148.0	1,148.0
5	Total Central Station Fuel Consumed	(000 BBLs)	1,143	1,135
6		(000 MBTUs)	7,020	7,009
7	Steam Fuel Consumed	(000 BBLs)	726	820
8		(000 MBTUs)	4,571	5,167
9	Diesel Fuel Consumed	(000 BBLs)	418	314
10		(000 MBTUs)	2,448	1,842
11	Total Central Station Net Heat Rate	(BTU / Net KWH)	13,644	13,646
12		(Net KWH / BBL)	450	453
13	Steam Net Heat Rate	(BTU / Net KWH)	14,347	14,342
14		(Net KWH / BBL)	439	439
15	Diesel Net Heat Rate	(BTU / Net KWH)	12,500	12,013
16		(Net KWH / BBL)	469	488
17	Central Station with Wind/Hydro Sales Heat Rate	(MBTU / KWH Sales)	0.014874	0.014872
18	Steam Sales Heat Rate	(MBTU / KWH Sales)	0.015640	0.015631
19	Diesel Sales Heat Rate	(MBTU / KWH Sales)	0.013627	0.013089
20	Wind/Hydro Sales Heat Rate	(MBTU / KWH Sales)	0.014874	0.014803

CA Reference
Line 1: Line 2 + Line 3
Lines 2 - 3: CA-WP-204, page 2
Line 4: CA-203, page 1
Line 5: Line 7 + Line 9
Line 6: Line 8 + Line 10
Lines 7 - 10: CA-WP-204, page 2
Line 11: Line 6 ÷ Line 1
Line 12: Line 1 ÷ Line 5
Line 13: Line 8 ÷ Line 2
Line 14: Line 2 ÷ Line 7
Line 15: Line 10 ÷ Line 3
Line 16: Line 3 ÷ Line 9
Lines 17 - 20: CA-WP-206, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

HISTORICAL FUEL EFFICIENCY
Direct Testimony

							HELCO DT			CA DT		
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
							Test Year	TY vs. 2005		Test Year	TY vs. 2005	
Line		2001	2002	2003	2004	2005	2006	Diff	%	2006	Diff	%
1	Helco Net Heat Rate (BTU / KWH)	13,524	13,552	13,758	13,136	13,167	13,644	477	3.6	13,646	479	3.6
2	Steam Net Heat Rate (BTU / KWH)	14,393	14,492	14,277	13,780	14,019	14,347	327	2.3	14,342	322	2.3
3	Diesel Net Heat Rate (BTU / KWH)	13,636	12,609	12,933	12,962	12,464	12,500	36	0.3	12,013	(450)	(3.6)

Reference:
Columns A - H: HELCO-407
Column I: CA-206, line 11
Column J: Column I - Column E
Column K: Column J ÷ Column E

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF FUEL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT (A) Average Burn Rate (BBL/Day)	(B) Fuel Inventory (BBLs)	(C) Fuel Inventory ($)	CA DT (D) Average Burn Rate (BBL/Day)	(E) Fuel Inventory (BBLs)	(F) Fuel Inventory ($)
	Industrial Fuel Oil Inventory						
1	Shipman/Hill	1,728	52,854	$ 3,017,426	1,935	57,823	$ 3,301,150
2	Puna	640	19,501	$ 1,137,668	709	21,176	$ 1,235,405
3	TOTAL INDUSTRIAL FUEL OIL INVENTORY	2,367	72,355	$ 4,155,094	2,644	79,000	$ 4,536,555
	Diesel Fuel Inventory						
4	Puna	221	7,043	$ 611,054	131	4,342	$ 376,752
5	Waimea	5	668	$ 58,632	9	794	$ 69,648
6	Kanoelehua	27	1,208	$ 104,776	30	1,358	$ 117,736
7	Keahole	1,215	37,877	$ 3,334,874	732	23,379	$ 2,058,444
8	TOTAL CENTRAL STATION DIESEL FUEL INVENTORY	1,467	46,796	$ 4,109,336	901	29,873	$ 2,622,580
9	Distributed Generators	1	17	$ 1,645	1	24	$ 2,247
10	TOTAL	3,836	119,168	$ 8,266,075	3,546	108,897	$ 7,161,382

CA Reference:
Line 1: CA-208, page 2
Line 2: CA-208, page 3
Line 4: CA-208, page 4
Line 5: CA-208, page 5
Line 6: CA-208, page 6
Line 7: CA-208, page 7
Line 9: CA-208, page 8

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF SHIPMAN/HILL INDUSTRIAL FUEL OIL INVENTORY
TEST YEAR 2006
Direct Testimony

Line			HELCO DT Test Year 2006		CA DT Test Year 2006	
1	Test Year Shipman/Hill Burn Rate		1,728		1,935	BBL / Day
2	24 Day Inventory (Line 1 x 24 Days)		41,470		46,439	BBLs
3	+ Dead Storage		11,384		11,384	BBLs
4	Total Industrial Fuel Oil BBL Inventory (Line 2 + Line 3)		52,854		57,823	BBLs
5	Fuel Price	$	57.0902	$	57.0902	/ BBL
6	Industrial Fuel Oil Inventory (Line 4 x Line 5)	$	3,017,426	$	3,301,150	

CA Reference:
Line 1: CA-WP-208, page 1
Line 3: HELCO-408, page 2
Line 5: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF PUNA INDUSTRIAL FUEL OIL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT Test Year 2006	CA DT Test Year 2006	
1	Test Year Puna Burn Rate	640	709	BBL / Day
2	24 Day Inventory (Line 1 x 24 Days)	15,349	17,024	BBLs
3	+ Dead Storage	4,152	4,152	BBLs
4	Total Industrial Fuel Oil BBL Inventory (Line 2 + Line 3)	19,501	21,176	BBLs
5	Fuel Price	$ 58.3389	$ 58.3389	/ BBL
6	Industrial Fuel Oil Inventory (Line 4 x Line 5)	$ 1,137,668	$ 1,235,405	

CA Reference:
Line 1: CA-WP-208, page 1
Line 3: HELCO-408, page 3
Line 5: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF PUNA DIESEL FUEL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT Test Year 2006	CA DT Test Year 2006	
1	Test Year Ignitor Diesel Fuel Consumption	274	274	BBLs
2	÷ Days Per Year	365	365	Days
3	Ignitor Diesel Burn Rate (Line 1 ÷ Line 2)	1	1	BBL / Day
4	Test Year Puna Diesel Burn Rate	220	130	BBL / Day
5	Total Puna Diesel Burn Rate (Line 3 + Line 4)	221	131	BBL / Day
6	30 Day Inventory (Line 5 x 30 Days)	6,628	3,927	BBLs
7	+ Dead Storage	415	415	BBLs
8	Total Diesel Fuel BBL Inventory (Line 6 + Line 7)	7,043	4,342	BBLs
9	Fuel Price	$ 86.7656	$ 86.7656	/ BBL
10	Diesel Fuel Inventory (Line 8 x Line 9)	$ 611,054	$ 376,752	

CA Reference:
Line 1: HELCO-408, page 4
Line 4: CA-WP-208, page 2
Line 7: HELCO-408, page 4
Line 9: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF WAIMEA DIESEL FUEL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT Test Year 2006	CA DT Test Year 2006	
1	Test Year Waimea Burn Rate	5	9	BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)	144	270	BBLs
3	+ Dead Storage	524	524	BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)	668	794	BBLs
5	Fuel Price	$ 87.7341	$ 87.7341	/ BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$ 58,632	$ 69,648	

CA Reference:
Line 1: CA-WP-208, page 2
Line 3: HELCO-408, page 5
Line 5: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF KANOELEHUA DIESEL FUEL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT Test Year 2006	CA DT Test Year 2006	
1	Test Year Ignitor Diesel Fuel Consumption	562	562	BBLs
2	÷ Days Per Year	365	365	Days
3	Ignitor Diesel Burn Rate (Line 1 ÷ Line 2)	2	2	BBL / Day
4	Test Year Kanoelehua Diesel Burn Rate	25	30	BBL / Day
5	Total Kanoelehua Diesel Burn Rate (Line 3 + Line 4)	27	32	BBL / Day
6	30 Day Inventory (Line 5 x 30 Days)	803	953	BBLs
7	+ Dead Storage	405	405	BBLs
8	Total Diesel Fuel BBL Inventory (Line 6 + Line 7)	1,208	1,358	BBLs
9	Fuel Price	$ 86.7252	$ 86.7252	/ BBL
10	Diesel Fuel Inventory (Line 8 x Line 9)	$ 104,776	$ 117,736	

CA Reference:
Line 1: HELCO-408, page 6
Line 4: CA-WP-208, page 2
Line 7: HELCO-408, page 6
Line 9: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF KEAHOLE DIESEL FUEL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT Test Year 2006	CA DT Test Year 2006	
1	Test Year Keahole Burn Rate	1,215	732	BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)	36,448	21,950	BBLs
3	+ Dead Storage	1,429	1,429	BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)	37,877	23,379	BBLs
5	Fuel Price	$ 88.0456	$ 88.0456	/ BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$ 3,334,874	$ 2,058,444	

CA Reference:
Line 1: CA-WP-208, page 2
Line 3: HELCO-408, page 7
Line 5: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF DISTRIBUTED GENERATORS DIESEL FUEL INVENTORY
TEST YEAR 2006
Direct Testimony

Line		HELCO DT Test Year 2006	CA DT Test Year 2006	
1	Test Year Diesel Fuel Consumption	213	291	BBLs
2	÷ Days Per Year	365	365	Days
3	Burn Rate (Line 1 ÷ Line 2)	1	1	BBL / Day
4	30 Day Inventory (Line 3 x 30 Days)	17	24	BBLs
5	+ Dead Storage	0	0	BBLs
6	Total Diesel Fuel BBL Inventory (Line 4 + Line 5)	17	24	BBLs
7	Fuel Price	$ 94.0338	$ 94.0338	/ BBL
8	Diesel Fuel Inventory (Line 6 x Line 7)	$ 1,645	$ 2,247	

CA Reference:
Line 1: CA-204
Line 5: HELCO-408, page 8
Line 7: CA-202

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

HISTORICAL AVERAGE FUEL INVENTORY
(Barrels)
Direct Testimony

Line		(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	HELCO DT (F) Test Year 2006	HELCO DT (G) TY vs. 2005 Diff	HELCO DT (H) TY vs. 2005 %	CA DT (I) Test Year 2006	CA DT (J) TY vs. 2005 Diff	CA DT (K) TY vs. 2005 %
	Industrial Fuel Oil											
1	Avg Inventory	61,401	62,503	69,422	67,127	75,756	72,355	(3,401.6)	(4.49)	79,000	3,243.5	4.28
2	Avg No. of Days	32	33	39	42	35	24			24		
	Diesel Fuel											
3	Avg Inventory	32,467	27,201	33,707	37,843	42,857	46,796	3,938.8	9.19	29,873	(12,984.0)	(30.30)
4	Avg No. of Days	65	30	47	45	38	30			30		

CA Reference:
Columns A - H: HELCO-409, page 1
Column I: CA-208, pages 2-7
Column J: Column I - Column E
Column K: Column J ÷ Column E

Note:
Column F & I, lines 2 and 4 are based on the average of the highest three monthly consumption rates in the test year as explained in the direct testimony. The average days of supply based on the annual average consumption rate in the test year is 37 and 41 for IFO and diesel fuel, respectively.

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

HISTORICAL DISTRIBUTED GENERATORS FUEL CONSUMPTION
Direct Testimony

							HELCO DT			CA DT		
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
							Test Year	TY vs. 2005		Test Year	TY vs. 2005	
Line		2001	2002	2003	2004	2005	2006	Diff	%	2006	Diff	%
1	Fuel Consumption (Barrels)	813	1,894	535	279	187	213	25.4	13.53	291	103.2	55.07
2	Fuel Expense ($)	50,334	104,093	30,822	18,057	15,001	20,015	5,014.2	33.43	27,337	12,336.3	82.24

CA Reference:
Columns A - H: HELCO-409, page 2
Column I: CA-204
Column J: Column I - Column E
Column K: Column J ÷ Column E

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Present Rates

Line			
1	Effective Date	2006 Test Year - Direct	
	Supercedes Factors of		
	HELCO GENERATION COMPONENT		
	FUEL PRICES, ¢/mmbtu		
2	Shipman Industrial		909.92
3	Hill Industrial		909.92
4	Puna Industrial		929.74
5	Keahole Diesel		1,502.48
6	Waimea Diesel		1,497.17
7	Hilo Diesel		1,479.95
8	Puna Diesel		1,480.64
9	Wind		0.00
10	Hydro		0.00
11	Dispersed		1,604.67
	BTU MIX, %		
12	Shipman Industrial		11.06
13	Hill Industrial		39.53
14	Puna Industrial		19.47
15	Keahole Diesel		21.51
16	Waimea Diesel		0.09
17	Hilo Diesel		0.66
18	Puna Diesel		2.72
19	Wind		0.31
20	Hydro		4.63
21	Dispersed		0.02
			100.00
22	COMPOSITE COST OF GENERATION, ¢/mmbtu		1,015.99
23	% Input to System kwh Mix		43.19
24	Efficiency Factor, mmbtu/kwh		0.014629
25	WEIGHTED COMPOSITE GEN COST, ¢/kwh (lines (22x23x24))		6.41929
26	BASE GEN. COST, ¢/mmbtu		469.72
27	Base % Input to Sys kwh Mix		27.09
28	Efficiency Factor, mmbtu/kwh		0.014629
29	WEIGHTED BASE GEN COST, ¢/kwh (lines (26x27x28))		1.8615
30	COST LESS BASE (line(25-29))		4.55779
31	Rev Tax Req Multiplier		1.0975
32	*GENERATION FACTOR, ¢/kwh* (line (30x31))		5.00217

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kwh		
33	HEP		12.140
34	PGV	On Peak	17.450
35	PGV	Off Peak	14.110
36	PGV Addt'l	On Peak	13.032
37	PGV Addt'l	Off Peak	12.033
38	Wailuku Hydro	On Peak	17.450
39	Wailuku Hydro	Off Peak	14.110
40	Hawi Renewable	On Peak	17.450
41	Hawi Renewable	Off Peak	14.110
42	Apollo (Kamaoa)	On Peak	14.833
43	Apollo (Kamaoa)	Off Peak	11.994
44	Other (>100 KW)	On Peak	17.450
45	Other (>100 KW)	Off Peak	14.110
46	Other (<100 KW)		15.870
	PURCHASED ENERGY KWH MIX, %		
47	HEP		59.35
48	PGV	On Peak	15.39
49	PGV	Off Peak	10.34
50	PGV Addt'l	On Peak	3.08
51	PGV Addt'l	Off Peak	2.35
52	Wailuku Hydro	On Peak	2.25
53	Wailuku Hydro	Off Peak	1.61
54	Hawi Renewable	On Peak	2.81
55	Hawi Renewable	Off Peak	2.01
56	Apollo (Kamaoa)	On Peak	0.48
57	Apollo (Kamaoa)	Off Peak	0.20
58	Other (>100 KW)	On Peak	0.07
59	Other (>100 KW)	Off Peak	0.05
60	Other (<100 KW)		0.03
			100.00
61	COMPOSITE COST OF PURCHASED ENERGY, ¢/kwh		13.544
62	% Input to System kwh Mix		56.81
63	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kwh (lines (61x62))		7.69435
64	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kwh		6.404
65	Base % Input to Sys kwh Mix		72.91
66	WEIGHTED BASE PURCH ENERGY COST, ¢/kwh (lines (64x65))		4.66916
67	COST LESS BASE(line(63 - 66))		3.02519
68	Loss Factor		1.090
69	*Rev Tax Req Multiplier*		1.0975
70	PURCHSD ENERGY FCTR, ¢/kwh (lines (67x68x69))		3.61896

LINE	SYSTEM COMPOSITE	
71	FUEL AND PURCHASED ENERGY FACTOR, ¢/kwh (lines (32+70))	8.62113
72	Not Used	0.000
73	Not Used	0.000
74	ECA Reconciliation Adjustment	0.000
75	*ECA FACTOR, ¢/kwh* (line(71+72+73+74))	8.621

CA Reference
Lines 2 - 21: CA-WP-211, page 3
Line 23: CA-WP-215, page 5
Line 24, 26 - 28, 31: HELCO-305
Lines 33 - 60, CA-WP-211, page 1
Line 62: CA-WP-215, page 5
Lines 64 - 65, 68 - 69: HELCO-305

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 PURCHASED POWER EXPENSE TOTAL
Direct Testimony

Line	Purchased Power ($000)	HELCO DT (A) Energy Payments ($000)	HELCO DT (B) Capacity Payments ($000)	HELCO DT (C) Total Payments ($000)	CA DT (D) Energy Payments ($000)	CA DT (E) Capacity Payments ($000)	CA DT (F) Total Payments ($000)
	Firm Power:						
1	Puna Geothermal Venture (PGV)	$ 34,393	$ 4,256	$ 38,649	$ 34,321	$ 4,256	$ 38,577
2	Hamakua Energy Partners (HEP)	$ 54,246	$ 13,674	$ 67,920	$ 53,777	$ 13,674	$ 67,451
	As Available Power:						
3	Wailuku River Hydro (WRH)	$ 4,412		$ 4,412	$ 4,412		$ 4,412
4	Hawi Renewable Development (HRD)	$ 5,496		$ 5,496	$ 5,496		$ 5,496
5	Apollo Energy Corp (Kamaoa)	$ 677		$ 677	$ 677		$ 677
6	Other Small Hydro	$ 164		$ 164	$ 164		$ 164
7	Total	$ 99,388	$ 17,930	$ 117,318	$ 98,846	$ 17,930	$ 116,776

CA Reference:
Column D = CA-WP-211, page 1, column (F)
Column E = HELCO-545
Column F = Column D + Column E

Note: Totals may not add exactly due to rounding.

CA-211
Docket No. 05-0315

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 NET PURCHASED ENERGY (GWH)
Direct Testimony

Purchased Power	HELCO DT 2006 Test Year (GWH)	CA DT 2006 Test Year (GWH)
Firm Power:		
1. Puna Geothermal Venture (PGV)	221.9	221.5
2. Hamakua Energy Partners (HEP)	420.6	421.9
Subtotal Firm Power	642.5	643.4
As Available Power:		
3. Wailuku River Hydro	27.5	27.5
4. Hawi Renewable Development	34.2	34.2
5. Apollo Energy Corp (Kamaoa Wind Farm)	4.8	4.8
6. Other Small Hydro	1.0	1.0
Subtotal As-Available Power	67.6	67.6
Total Purchased Power (GWH)	710.1	711.0

CA Reference:
CA-WP-211, page 1

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

HISTORICAL PURCHASED ENERGY (ANNUAL GWH)
Direct Testimony

Purchased Power (GWH)	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	**HELCO Test Year 2006**	**CA Test Year 2006**
Firm Power:							
1. Puna Geothermal Venture (PGV)	207	74	176	211	221	**222**	**221**
2. Hamakua Energy Partners (HEP)	322	421	439	442	431	**421**	**422**
3. Hilo Coast Power Company (HCPC)	69	89	82	79	-	-	-
Subtotal Firm Power	598	584	697	731	652	**643**	**643**
As Available Power:							
4. Wailuku River Hydro	33	27	24	26	30	**27**	**27**
5. Hawi Renewable Development	-	-	-	-	-	**34**	**34**
6. Apollo Energy Corp (Kamaoa Wind Farm)	15	10	10	6	5	**5**	**5**
7. Other Small Wind and Hydro	1	1	1	1	1	**1**	**1**
Subtotal As-Available Power	49	38	35	33	35	**68**	**68**
Total HELCO Purchased Power	648	622	732	764	688	**710**	**711**

CA Reference:
CA-212, page 1

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

HISTORICAL PURCHASED POWER EXPENSES
Direct Testimony

Purchased Power Expense	2004 Recorded ($000)	2005 Recorded ($000)	HELCO 2006 Test Year Estimate ($000)	CA 2006 Test Year Estimate ($000)
1. Puna Geothermal Venture (PGV)	$ 21,067	$ 30,746	$ 34,393	$ 34,321
2. Hamakua Energy Partners (HEP)	$ 37,489	$ 49,380	$ 54,246	$ 53,777
3. Hilo Coast Power Company (HCPC)	$ 7,040	$ -	$ -	$ -
4. Wailuku River Hydro (WRH)	$ 2,555	$ 4,394	$ 4,412	$ 4,412
5. Hawi Renewable Development (HRD)	$ -	$ -	$ 5,496	$ 5,496
6. Apollo Energy Corporation (AEC)	$ 535	$ 573	$ 677	$ 677
7. Other Small Wind & Hydro	$ 62	$ 129	$ 164	$ 164
Total Energy Payments	$ 68,748	$ 85,222	$ 99,388	$ 98,846
1. Puna Geothermal Venture (PGV)	$ 3,950	$ 4,104	$ 4,256	$ 4,256
2. Hamakua Energy Partners (HEP)	$ 13,500	$ 13,569	$ 13,674	$ 13,674
3. Hilo Coast Power Company (HCPC)	$ 4,930	$ -	$ -	$ -
Total Capacity Payments	$ 22,380	$ 17,672	$ 17,930	$ 17,930
Total HELCO Purchased Power Expense	$ 91,128	$ 102,894	$ 117,318	$ 116,776

CA Reference:
CA-211, page 1

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.
COMPOSITE COST OF GENERATION - CENTRAL STATION WITH WIND/HYDRO
2006 Test Year - Direct Testimony

		(A) At Present Rates	(B) At Proposed Rates	(C) Difference (B)-(A)	(D) At Proposed Rates	(E) Difference (B)-(D)
	FUEL PRICES, ¢/mmbtu					
1	Shipman Industrial	910.41	948.35	37.94	909.92	38.43
2	Hill Industrial	910.41	910.53	0.12	909.92	0.61
3	Puna Industrial	930.23	930.23	0.00	929.74	0.49
4	Keahole Diesel	1,502.48	1,502.48	0.00	1,502.48	(0.00)
5	Waimea Diesel	1,497.17	1,497.17	0.00	1,497.17	0.00
6	Kanoelehua Diesel	1,479.95	1,479.95	0.00	1,479.95	(0.00)
7	Puna Diesel	1,480.64	1,480.64	0.00	1,480.64	(0.00)
8	Wind	0.00	0.00	0.00	0.00	0.00
9	Hydro	0.00	0.00	0.00	0.00	0.00
10	Dispersed	0.00	0.00	0.00	0.00	0.00
	BTU MIX, %					
11	Shipman Industrial	8.17	8.17	0.00	11.06	(2.89)
12	Hill Industrial	36.88	36.88	0.00	39.53	(2.65)
13	Puna Industrial	16.85	16.85	0.00	19.47	(2.62)
14	Keahole Diesel	28.16	28.16	0.00	21.51	6.65
15	Waimea Diesel	0.10	0.10	0.00	0.09	0.01
16	Kanoelehua Diesel	0.57	0.57	0.00	0.66	(0.09)
17	Puna Diesel	4.33	4.34	0.01	2.72	1.62
18	Wind	0.31	0.31	0.00	0.31	0.00
19	Hydro	4.62	4.62	0.00	4.63	(0.01)
20	Dispersed	0.01	0.00	(0.01)	0.00	0.00
		100.00	100.00	(0.00)	99.98	0.02
21	COMPOSITE COST OF GENERATION, CENTRAL STATION WITH WIND/HYDRO (¢/mmbtu)	1,064.03	1,067.32	3.29	1,015.99	1,012.70

CA Reference:
Column A: HELCO-306
Column B: HELCO-306
Column D: CA-215, page 1

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

Line		
1	Effective Date	2006 Test Year - Direct
2	Supercedes Factors of	

GENERATION COMPONENT

CENTRAL STATION WITH WIND/HYDRO COMPONENT

Line		
	FUEL PRICES, ¢/mmbtu	
3	Shipman Industrial	909.92
4	Hill Industrial	909.92
5	Puna Industrial	929.74
6	Keahole Diesel	1,502.48
7	Waimea Diesel	1,497.17
8	Hilo Diesel	1,479.95
9	Puna Diesel	1,480.64
10	Wind	0.00
11	Hydro	0.00
	BTU MIX, %	
12	Shipman Industrial	11.06
13	Hill Industrial	39.53
14	Puna Industrial	19.47
15	Keahole Diesel	21.51
16	Waimea Diesel	0.09
17	Hilo Diesel	0.66
18	Puna Diesel	2.72
19	Wind	0.31
20	Hydro	4.63
		99.98
21	COMPOSITE COST OF GENERATION, CNTRL STN+WIND/HYDRO ¢/mmbtu	1,015.99
22	% Input to System kWh Mix	43.19

EFFICIENCY FACTOR, mmbtu/kWh

Line	(A) Fuel Type	(B) Eff Factor mmbtu/kwh	(C) Percent of Cntrl Stn + Wind/Hydro	(D) Weighted Eff Factor
23	Industrial	0.015631	66.68	0.010423
24	Diesel	0.013089	28.39	0.003716
25	Other	0.014803	4.93	0.000730

(Lines 23, 24, 25): Col(D) = Col(B) x Col(C)

Line		
26	Weighted Efficiency Factor, mmbtu/kWh [lines 23(D) + 24(D) + 25(D)]	0.014869
27	WGTD. COMPOSITE CNTRL STN + WIND/HYDRO GEN COST, ¢/kWh (lines (21x22x26))	6.52461
28	BASE CNTRL STN + WND/HYDRO GEN. COST, ¢/mmbtu	1,015.99
29	Base % Input to Sys kWh Mix	43.19
30	Efficiency Factor, mmbtu/kwh	0.014872
31	WEIGHTED BASE CNTRL STN + WIND/HYDRO GEN COST ¢/kWh (lines (28x29x30))	6.52572
32	COST LESS BASE (line(27-31))	(0.00111)
33	Revenue Tax Req Multiplier	1.0975
34	CNTRL STN+WIND/HYDRO GENERATION FACTOR, ¢/kWh (line (32x33))	(0.00122)

DG ENERGY COMPONENT

Line		
35	COMPOSITE COST OF DG ENERGY, ¢/kWh	21.298
36	% Input to System kWh Mix	0.01
37	WTD COMP DG ENRGY COST, ¢/kWh (Lines 35 x 36)	0.00213
38	BASE DG ENERGY COMP COST	21.298
39	Base % Input to System kWh Mix	0.01
40	WTD BASE DG ENERGY COST, ¢/kWh (Line 38 x 39)	0.00213
41	Cost Less Base (Line 37 - 40)	0.00000
42	Loss Factor	1.090
43	Revenue Tax Req Multiplier	1.0975
44	DG FACTOR, ¢/kWh (Line 41 x 42 x 43)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

Line		
45	Cntrl Stn+Wind/Hydro (line 34)	(0.00122)
46	DG (line 44)	0.00000
47	TOTAL GENERATION FACTOR, ¢/kWh (lines 45 + 46)	(0.00122)

CA Reference:
Lines 1 - 20: CA-WP-215, page 3
Line 22: CA-WP-215, page 5
Lines 23 - 25, column (B): CA-WP-206, page 1
Lines 23 - 25, column (C): CA-WP-215, page 4
Line 28: CA-WP-215, page 9
Line 30: CA-WP-206, page 1
Line 33: HELCO-307, page 1
Line 35: CA-WP-215, page 7
Line 36: CA-WP-215, page 5
Line 42: CA-WP-215, page 8
Line 43: HELCO-307, page 1

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kWh		
48	HEP		12.140
49	PGV	On Peak	17.450
50	PGV	Off Peak	14.110
51	PGV - Addt'l	On Peak	13.032
52	PGV - Addt'l	Off Peak	12.033
53	Wailuku Hydro	On Peak	17.450
54	Wailuku Hydro	Off Peak	14.110
55	Hawi Renewable Dev.	On Peak	17.450
56	Hawi Renewable Dev.	Off Peak	14.110
57	Apollo (Kamaoa)	On Peak	14.833
58	Apollo (Kamaoa)	Off Peak	11.994
59	Other (>100 KW)	On Peak	17.450
60	Other (>100 KW)	Off Peak	14.110
61	Other (<100 KW)		15.870
	PURCHASED ENERGY KWH MIX, %		
62	HEP		59.35
63	PGV	On Peak	15.39
64	PGV	Off Peak	10.34
65	PGV - Addt'l	On Peak	3.08
66	PGV - Addt'l	Off Peak	2.35
67	Wailuku Hydro	On Peak	2.25
68	Wailuku Hydro	Off Peak	1.61
69	Hawi Renewable Dev.	On Peak	2.81
70	Hawi Renewable Dev.	Off Peak	2.01
71	Apollo (Kamaoa)	On Peak	0.48
72	Apollo (Kamaoa)	Off Peak	0.20
73	Other (>100 KW)	On Peak	0.07
74	Other (>100 KW)	Off Peak	0.05
75	Other (<100 KW)		0.03
			100.00
76	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh		13.543
77	% Input to System kWh Mix		56.81
78	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (76x77))		7.69378
79	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh		13.544
80	Base % Input to Sys kWh Mix		56.81
81	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (79 x 80))		7.69435
82	COST LESS BASE(lines (78 - 81))		(0.00057)
83	Loss Factor		1.090
84	Revenue Tax Req Multiplier		1.0975
85	PURCHSD ENERGY FCTR, ¢/kWh (lines (82 x 83 x 84))		(0.00068)

Line	SYSTEM COMPOSITE	
86	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (47 + 85))	(0.00190)
87	Not Used	0.000
88	Not Used	0.000
89	ECA Reconciliation Adjustment	0.000
90	ECA FACTOR, ¢/kWh (lines (86 + 87+ 88 + 89))	(0.002)

CA Reference:
Lines 48 - 75: CA-WP-210, page 1
Line 77: CA-WP-215, page 5
Line 79: CA-WP-210, page 1
Line 83: CA-WP-215, page 8
Line 84: HELCO-307, page 1

Hawaii Electric Light Company, Inc.
WEIGHTED COMPOSITE GENERATION COST CALCULATIONS
2006 Test Year - Direct Testimony

	Industrial	Diesel	Other	Total	
1 Fixed Efficiency Factor	0.015631	0.013089	0.014803		mbtu/kwh
2 Gen MWh %	66.68	28.39	4.93	100.00	%
3 Weighted Efficiency Factor (line 1 x line 2)	0.010423	0.003716	0.000730	0.014869	mbtu/kwh

CA Reference:

Line 1: CA-WP-206, page 1

Line 2: CA-WP-215, page 4

Hawaii Electric Light Company, Inc.
Determination of Base Fuel Energy Charge at Proposed Rates
(¢/kWh)

Line	Description	HELCO DT Position	CA DT Position	CA Reference
1	**Weighted Base Generation Cost**	6.86607	6.52572	CA-215, Page 1, Line 31
2	**Revenue Tax Factor**	1.09750	1.09750	CA-215, Page 1, Line 33
3	**Generation Fuel Cost Component**	7.53551	7.16198	Line 1 x Line 2
4	**Weighted Base DG Energy Cost**	0.00153	0.00213	CA-215, Page 1, Line 40
5	**Revenue Tax Factor**	1.09750	1.09750	CA-215, Page 1, Line 43
6	**DG Fuel Cost Component**	0.00168	0.00234	Line 4 x Line 5
7	**Weighted Base Purchased Energy Cost**	7.73366	7.69435	CA-215, Page 2, Line 81
8	**Revenue Tax Factor**	1.09750	1.09750	CA-215, Page 2, Line 84
9	**Purchased Energy Cost Component**	8.48769	8.44455	Line 7 x Line 8
10	**Base Fuel Energy Charge at Proposed Rates**	16.02488	15.60886	Line 3 + Line 6 + Line 9

Power Factor--
The Basics

We hope to give you an explanation of what power factor is, and to answer the following questions:

- Question #1: What is Power Factor?
- Question #2: What Causes Low Power Factor?
- Question #3: Why Should I Improve My Power Factor?
- Question #4: How Do I Correct (Improve) My Power Factor?
- Question #5: How Long Will it Take My Investment in Power Factor Correction to Pay for Itself?

Question #1

What is Power Factor?

To understand power factor, we'll first start with the definition of some basic terms:

- **KW** is Working Power (also called Actual Power or Active Power or Real Power). It is the electric energy that actually powers the equipment and performs useful work.

- **KVAR** is Reactive Power. It is the power that magnetic equipment (transformer, motor and relay) needs to produce the magnetizing flux.

- **KVA** is Apparent Power. It is the "vectorial summation" of KVAR and KW.

Let's look at an analogy in order to better understand these terms...

Let's say you are at the ballpark and it is a really hot day. You order up a mug of your favorite brewsky. The thirst-quenching portion of your beer is represented by KW (Figure 1).

Unfortunately, life isn't perfect. Along with your ale comes a little bit of foam. (And let's face it...that foam just doesn't quench your thirst.) This foam is represented by KVAR.

The total contents of your mug, KVA, is the summation of KW (the beer) and KVAR (the foam).

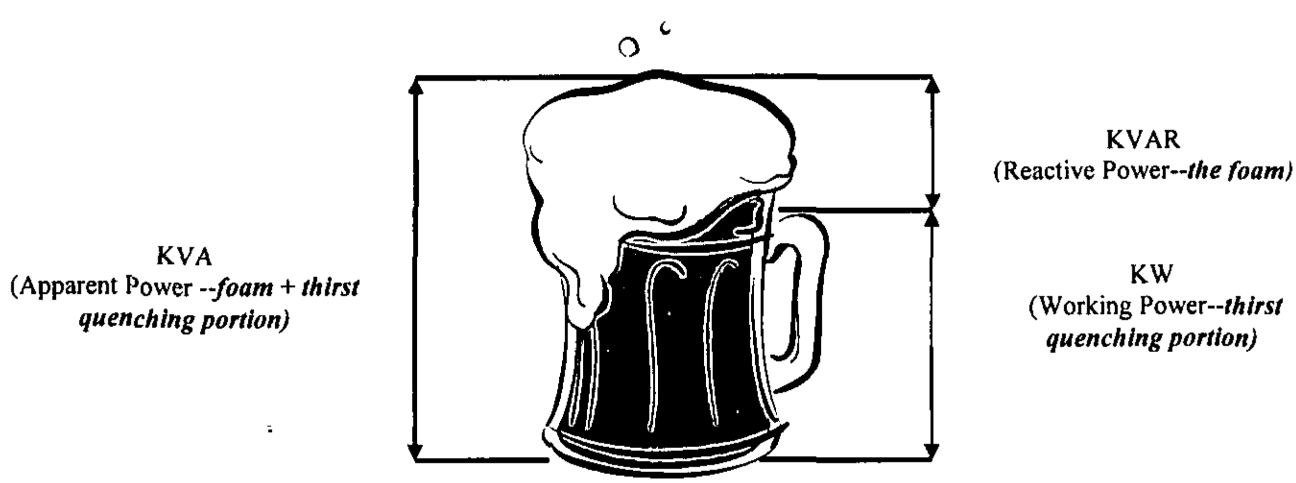

Figure 1

So, now that we understand some basic terms, we are ready to learn about power factor.

Power Factor (P.F.) is the ratio of Working Power to Apparent Power.

$$\text{P.F.} = \frac{\text{KW}}{\text{KVA}}$$

Thus, for a given KVA:

- The more foam you have, the lower your ratio of KW (beer) to KVA (beer plus foam). *Thus, the lower your power factor percentage.*
- The less foam you have, the higher your ratio of KW (beer) to KVA (beer plus foam). In fact, as your foam (or KVAR) approaches zero, your power factor approaches 100%.

Question #2:

What Causes Low Power Factor?

Since power factor is defined as the ratio of KW to KVA, we see that low power factor results when KW is small in relation to KVA. Remembering our beer mug analogy, this would occur when KVAR (foam) is large.

What causes a large KVAR in a system? The answer is.....**inductive loads.**

Inductive loads (which are sources of Reactive Power) include:

- Transformers
- Induction Motors
- High Intensity Discharge (HID) Lighting

These inductive loads constitute a major portion of the power consumed in industrial complexes. Reactive power (KVAR) required by inductive loads increases the amount of apparent power (KVA) in the electric system. So, inductive loads (with large KVAR) result in low power factor.

Question #3

Why Should I Improve My Power Factor?

Okay. So I've got inductive loads at my facility that are causing my power factor to be low. Why should I want to improve it?

You want to improve your power factor for several different reasons. Some of the benefits of improving your power factor include:

1) **Lower utility fees** by:

   a. Reducing peak KW billing demand

      Recall that inductive loads, which require reactive power, caused your low power factor. This increase in required reactive power (KVAR) causes an increase in required apparent power (KVA), which is what the electric system is supplying.

      So, a facility's low power factor causes the electric system to increase its generation, transmission, distribution and transformer capacity in order to handle this extra apparent power (KVA) demand. Also, a facility's low power factor increases the energy losses on the electric system.

      By lowering your power factor, you require less KVA from the electric system. This equates to a dollar savings from the utility.

   b. Eliminating the power factor penalty

      Utilities usually charge customers an additional fee when their power factor is less than 95%. In fact, power factor less than 70% will not be permitted by most electric systems and the customer will be required to install, at their own expense, such corrective equipment as may be necessary to improve power factor.

2) **Increased system capacity** and **reduced system losses** in your electrical system

   By adding capacitors (KVAR generators), the power factor is improved and the KW capacity of the system is increased.

Uncorrected power factor causes power system losses in your distribution system. By improving your power factor, these losses can be reduced. And with lower system losses, you are also able to add additional load to your system.

3) **Increased voltage level** in your electrical system and **cooler, more efficient motors**

As mentioned above, uncorrected power factor causes power system losses in your distribution system. As power losses increase, you may experience voltage drops. Excessive voltage drops can cause overheating and premature failure of motors and other inductive equipment.

So, by raising your power factor, you will minimize these voltage drops along feeder cables and avoid related problems. Your motors will run cooler and be more efficient, with a slight increase in capacity and starting torque.

Question # 4

How Do I Correct (Improve) My Power Factor?

All right. You've convinced me. I sure would like to save some money on my power bill and extend the life of my motors. But how do I go about improving (i.e., increasing) my power factor?

We have seen that **sources of Reactive Power** (inductive loads) decrease power factor:

- Transformers
- Induction motors
- High Intensity Discharge (HID) Lighting

Similarly, **consumers of Reactive Power** increase power factor:

- Capacitors
- Synchronous generators (utility and emergency)
- Synchronous motors

Thus, it comes as no surprise that one way to increase power factor is to add capacitors to the system. This--and other ways of increasing power factor--are listed below:

1) **Installing capacitors (KVAR Generators)**

   Installing capacitors decreases the magnitude of reactive power (KVAR or foam), thus increasing your power factor.

2) **Minimizing operation of idling or lightly loaded motors**

   We already talked about the fact that low power factor is caused by the presence of induction motors. But, more specifically, low power factor is caused by running induction motors lightly loaded.

3) **Avoiding operation of equipment above its rated voltage.**

4) **Replacing standard motors as they burn out with energy--efficient motors.**

Even with energy-efficient motors, power factor is significantly affected by variations in load. A motor must be operated near its rated load in order to realize the benefits of a high power factor design.

Question #5

How Long Will it Take My Investment in Power Factor Correction to Pay for Itself?

Super. I've learned that by installing capacitors at my facility, I can improve my power factor. But buying capacitors costs money. How long will it take for the reduction in my power bill to pay for the cost of the capacitors?

Using the following three steps, a calculation can be run to determine when this payoff will be:

1) Determine **amount of power factor penalty** caused by your low power factor.

2) Determine what needs to be done at your facility to improve the situation. Bring in an electrician or other qualified person to estimate the **cost of power improvement**.

3) **Calculate the payback by** comparing the power factor penalty to be avoided with the power factor improvement cost.

Hawaii Electric Light Company, Inc.

2006 TEST YEAR PRODUCTION SIMULATION
SUMMARY (UNADJUSTED)
Direct Testimony

Location	Unit No.	HELCO Production Simulation Results: Hours Run	Net MWHs	Fuel Consumption BBL	Fuel Consumption MBTU	CA Production Simulation Results: Hours Run	Net MWHs	Fuel Consumption BBL	Fuel Consumption MBTU
Shipman	3	3,409	17,989	48,095	303,000	4,326	23,553	61,964	390,372
	4	3,408	17,212	45,905	289,200	4,326	24,840	65,194	410,721
	Total	6,817	35,201	94,000	592,200	8,652	48,394	127,158	801,093
Hill	5	7,244	77,837	168,238	1,059,900	7,584	87,916	189,231	1,192,153
	6	6,602	130,886	256,460	1,615,700	6,912	135,417	265,364	1,671,791
	Total	13,846	208,723	424,698	2,675,600	14,496	223,334	454,594	2,863,944
Puna-Steam	Total	7,247	74,653	193,937	1,221,800	7,584	88,555	223,910	1,410,635
Waimea	D12	107	269	478	2,800	99	248	446	2,613
	D13	76	191	341	2,000	83	208	374	2,191
	D14	71	177	324	1,900	58	145	261	1,531
	Total	255	637	1,143	6,700	240	600	1,081	6,335
Kanoelehua	D11	57	114	205	1,200	1,799	2,120	4,328	25,361
	D15	147	368	666	3,900	358	895	1,613	9,450
	D16	132	330	597	3,500	222	555	1,000	5,860
	D17	122	304	546	3,200	133	333	599	3,511
	Sub Total	458	1,116	2,014	11,800	2,512	3,902	7,540	44,182
	CT1	253	901	4,693	27,500	17	81	350	2,048
	Total	710	2,017	6,706	39,300	2,529	3,983	7,889	46,230
Keahole	D21	1,616	4,040	7,287	42,700	1,118	2,795	5,036	29,512
	D22	1,536	3,840	6,911	40,500	704	1,760	3,171	18,583
	D23	1,404	3,510	6,331	37,100	289	723	1,302	7,629
	Sub Total	4,556	11,390	20,529	120,300	2,111	5,278	9,509	55,724
	CT2	665	7,809	18,345	107,500	28	301	730	4,279
	CT4	5,159	79,955	155,700	912,400	5,475	84,313	164,233	962,404
	CT5	4,959	72,211	143,003	838,000	2,638	43,053	83,106	487,003
	Total	15,338	171,365	337,577	1,978,200	10,252	132,945	257,578	1,509,409
Puna-Diesel	CT3	2,242	21,777	51,928	304,300	1,041	15,853	32,635	191,243
Dispersed Generators	D24	31	31	51	300	31	19	33	192
	D25	26	26	34	200	6	3	6	33
	D26	25	25	34	200	0	0	0	0
	D27	28	28	51	300	321	109	244	1,433
	Total	110	110	171	1,000	358	131	283	1,658
Wind/Hydro									
Lalamilo			1,691				1,656		
HelcoHydro			25,000				24,998		
	Total		26,691				26,653		
Wailuku			27,475				27,491		
Other Hydro			1,021				1,022		
Kamaoa			4,841				4,810		
HRD			34,222				34,252		
	Total		67,559				67,574		
IPP									
HEP		8,477	420,562			8,256	421,930		
PGV		7,733	221,944			8,088	221,476		
	Total	0	642,506			16,344	643,407		
IPP Total			710,065				710,981		
Helco Total			541,174				540,447		
SYSTEM TOTAL			*1,251,239*	*1,110,161*	*6,819,100*		*1,251,428*	*1,105,129*	*6,830,548*

	MBTU/BBL
IFO	6.3
Diesel	5.86

Hawaii Electric Light Company, Inc.

2006 TEST YEAR FUEL CONSUMPTION
PRODUCTION SIMULATION
Direct Testimony

Adjustment for Calibration Factor:

Steam	Net MWHs	Prod Sim Barrels	p. 54 Calibration Factor	Adjusted Barrels	Net KWH / Barrel	Barrels Per Day	MBTU @ 6.30 MBTU / BBL	Net Heat Rate (MBTU/KWH)
Shipman 3	23,553	61,964	1.018	63,079	373	173	397,398	16,872
Shipman 4	24,840	65,194	1.018	66,367	374	182	418,112	16,832
Total	48,394	127,158		129,446	374	355	815,510	16,852
Hill 5	87,916	189,231	1.018	192,637	456	528	1,213,613	13,804
Hill 6	135,417	265,364	1.018	270,140	501	740	1,701,882	12,568
Total	223,334	454,594		462,777	483	1,268	2,915,495	13,054
Puna	88,555	223,910	1.018	227,941	388	624	1,436,028	16,216
Steam Total	360,282	805,662		820,164	439	2,247	5,167,033	14,342

Diesels	Net MWHs	Prod Sim Barrels	p. 54 Calibration Factor	Adjusted Barrels	Net KWH / Barrel	Barrels Per Day	MBTU @ 5.86 MBTU / BBL	Net Heat Rate (MBTU/KWH)
Waimea	600	1,081	1.051	1,136	528	3	6,657	11,095
Kanoelehua	3,902	7,540	1.051	7,924	492	22	46,435	11,899
CT1	81	350	1.051	367	220	1	2,151	26,687
Total	3,983	7,889		8,291	480	23	48,585	12,198
Keahole	5,278	9,509	1.051	9,994	528	27	58,565	11,097
CT2	301	730	1.051	767	393	2	4,495	14,924
CT4	84,313	164,233	1.051	172,609	488	473	1,011,489	11,997
CT5	43,053	83,106	1.051	87,345	493	239	511,842	11,889
Total	132,945	257,578		270,715	491	742	1,586,390	11,933
Puna CT3	15,853	32,635	1.051	34,300	462	94	200,998	12,679
Distributed Generators	131	283	1.051	297	441	1	1,740	13,272
Diesel Total	153,512	299,467		314,739	488	862	1,844,371	12,015

Plant	Net MWHs		Adjusted Barrels	Barrels Per Day	Adjusted MBTU	Net HR (MBTU/KWH)
Shipman	48,394		129,446	355	815,510	16,852
Hill	223,334		462,777	1,268	2,915,495	13,054
Puna	88,555		227,941	624	1,436,028	16,216
Waimea	600		1,136	3	6,657	11,095
Kanoelehua/CT1	3,983		8,291	23	48,585	12,198
Keahole/CT2/CT4/CT5	132,945		270,715	742	1,586,390	11,933
Puna CT3	15,853		34,300	94	200,998	12,679
Distributed Generators	131		297	1	1,740	13,272
Wind/Hydro	26,653					
IPP	710,981	Helco Only MWH				
System	1,251,428	513794	1,134,903	3,109	7,011,403	13,646

Adjustment for EUE and Rounding: [1]

Plant	Net MWHs		Adjusted Barrels	Barrels Per Day	Adjusted MBTU	Net HR (MBTU/KWH)
Shipman	48,391		129,439		815,463	
Hill	223,331		462,771		2,915,459	
Puna	88,552		227,934		1,435,983	
Steam Total	***360,274***		***820,144***		***5,166,905***	*14,342*
Waimea	597		1,131		6,626	
Kanoelehua/CT1	3,980		8,285		48,551	
Keahole/CT2/CT4/CT5	132,942		270,709		1,586,357	
Puna CT3	15,850	Helco Only MWH	34,294		200,963	
Diesel Total	**153,370**	513772	**314,419**		**1,842,497**	12,013
Distributed Generators	**128**		**291**		**1,703**	
Wind/Hydro	26,653					
Ipp	710,986					
System	1,251,405	(Prod Sim Input)	1,134,854		7,011,105	13,646

[1] Adjustment to prorate -0.022 GWh difference in net generation between prod sim output and input (EUE & Rounding)

Hawaii Electric Light Company, Inc.

DERIVATION OF TEST YEAR 2006
WEIGHTED AVERAGE COST PER MBTU
Direct Testimony

Plant	Type	Adjusted Net MWHs	Adjusted MBTU	Fuel Price ($/MBTU)	Total Fuel Expense ($)	% MBTU
Shipman	Steam	48,391	815,463	9.0620	7,389,723	11.06
Hill	Steam	223,331	2,915,459	9.0620	26,419,872	39.53
Puna	Steam	88,552	1,435,983	9.2602	13,297,491	19.47
Waimea	Diesel	597	6,626	14.9718	99,206	0.09
Kanoelehua	Diesel	3,980	48,551	14.7996	718,537	0.66
Keahole	Diesel	132,942	1,586,357	15.0249	23,834,868	21.51
Puna CT3	Diesel	15,850	200,963	14.8065	2,975,553	2.72
Distributed Generators	Diesel	128	1,703	16.0467	27,330	0.02
	Sub-total	513,772	7,011,105		74,762,580	
Wind/Hydro		26,653	363,721			4.93
IPP		710,986				
		1,251,410	7,374,827		74,762,580	99.99

Plant	Type		Wtd Cost (¢ / MBTU)
Shipman	Steam		100.23
Hill	Steam		358.22
Puna	Steam		180.30
Waimea	Diesel		1.35
Kanoelehua	Diesel		9.77
Keahole	Diesel		323.19
Puna CT3	Diesel		40.27
Distributed Generators	Diesel		0.32
		TOTAL	1,013.65

Hawaii Electric Light Company, Inc.
Determination of Sales Heat Rate (Mbtu ./ Kwh Sales)
2006 Test Year - Direct Testimony
At Proposed Rates

Line				CA Reference
	Total Central Station Fuel + Wind/Hydro Sales Heat Rate			
1	Total Central Station Fuel + Wind/Hydro Consumed	7,373,123	Mbtu	CA-WP-215, page 3
2	Sales	1,148.0	Gwh	CA-203, page 1, line 1
3	% of Central Stn+Wind/Hydro Generation to Total System	43.19	Percent	CA-WP-215, page 5
4	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
5	Sales Heat Rate [line 1 ÷ (line 2 x line 3 x line 4)]	0.014872	Mbtu/Kwh Sales	
	Steam (Industrial Fuel) Sales Heat Rate			
6	Industrial Fuel Consumed	5,166,905	Mbtu	CA-WP-215, page 3
7	Sales	1,148.0	Gwh	CA-203, page 1, line 1
8	% of Industrial Fuel Generation to Total System	28.79	Percent	CA-WP-215, page 5
9	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
10	Sales Heat Rate [line 6 ÷ (line 7 x line 8 x line 9)]	0.015631	Mbtu/Kwh Sales	
	Diesel Fuel Sales Heat Rate			
11	Diesel Fuel Consumed	1,842,497	Mbtu	CA-WP-215, page 3
12	Sales	1,148.0	Gwh	CA-203, page 1, line 1
13	% of Diesel Fuel Generation to Total System	12.26	Percent	CA-WP-215, page 5
14	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
15	Sales Heat Rate [line 11 ÷ (line 12 x line 13 x line 14)]	0.013089	Mbtu/Kwh Sales	
	HELCO Wind/Hydro Sales Heat Rate			
16	HELCO Wind/Hydro Consumed	363,721	Mbtu	CA-WP-215, page 3
17	Sales	1,148.0	Gwh	CA-203, page 1, line 1
18	% of HELCO Wind/Hydro Generation to Total System	2.14	Percent	CA-WP-215, page 5
19	Kwh/Gwh Conversion	1,000,000	kwh/gwh	
20	Sales Heat Rate [line 16 ÷ (line 17 x line 18 x line 19)]	0.014803	Mbtu/Kwh Sales	

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 AVERAGE BURN RATE FOR FUEL INVENTORY
INDUSTRIAL FUEL OIL
Direct Testimony

Month	Shipman/Hill (Barrels/day)	Puna (Barrels/day)	TOTAL (Barrels/day)
January	1,690	700	2,390
February	1,258	729	1,986
March	1,690	700	2,390
April	**1,935**	**709**	**2,644**
May	1,690	700	2,390
June	1,935	709	2,644
July	1,690	700	2,390
August	1,690	700	2,390
September	**1,935**	**709**	**2,644**
October	1,690	700	2,390
November	**1,935**	**709**	**2,644**
December	1,690	700	2,390
Annual Average	1,736	706	2,441
TY2006 Burn Rate based on Average of April, September & November	**1,935**	**709**	**2,644**

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 AVERAGE BURN RATE FOR FUEL INVENTORY
DIESEL FUEL
Direct Testimony

Month	Puna (Barrels/day)	Waimea (Barrels/day)	Kanoelehua (Barrels/day)	Keahole (Barrels/day)	TOTAL (Barrels/day)
January	25	0	11	533	569
February	35	0	14	704	753
March	25	0	11	533	569
April	**130**	**9**	**30**	**732**	**900**
May	25	0	11	533	569
June	**130**	**9**	**30**	**732**	**900**
July	25	0	11	533	569
August	25	0	11	533	569
September	130	9	30	732	900
October	25	0	11	533	569
November	**130**	**9**	**30**	**732**	**900**
December	25	0	11	533	569
Annual Average	61	3	17	614	695
TY2006 Burn Rate based on Average of April, June, and November	**130**	**9**	**30**	**732**	**900**

Hawaii Electric Light Company, Inc.
Determination of Percent of Purchased Energy Mix,
Payment Rate (in ¢/kwh) and
Composite Cost of Purchased Energy (in ¢/kwh)
2006 Test Year - Direct Testimony
At Present Rates

No.	(A) Producer	(B) Mwh Purchased	(C) % to Total PP	(D) Payment Rate (¢/kwh)	(E) Weighted Cost (¢/kwh) [(colF ÷ colB) * colC * 1000]	(F) Purch Pwr Fuel Expense ($ thous)
1	**HEP**					
	Fuel	421,930	59.35	12.140	7.205	51,223.7
2	**PGV**					
	On Peak	109,384	15.39	17.450	2.685	19,087.5
	Off Peak	73,508	10.34	14.110	1.459	10,371.9
	On Peak - Addt'l	21,880	3.08	13.032	0.401	2,851.3
	Off Peak - Addt'l	16,705	2.35	12.033	0.283	2,010.1
	Total	221,476	31.15			34,320.8
3	**Wailuku**					
	On Peak	16,027	2.25	17.450	0.393	2,796.7
	Off Peak	11,448	1.61	14.110	0.227	1,615.3
	Total	27,475	3.86			4,412.0
4	**Hawi Renewabale Dev**					
	On Peak	19,966	2.81	17.450	0.490	3,484.2
	Off Peak	14,261	2.01	14.110	0.283	2,012.1
	Total	34,227	4.81			5,496.3
5	**Apollo (Kamaoa)**					
	On Peak	3,389	0.48	14.833	0.071	502.6
	Off Peak	1,452	0.20	11.994	0.024	174.2
	Total	4,841	0.68			676.8
6	**Other Small Hydro (>100 kw)**					
	On Peak	488	0.07	17.450	0.012	85.2
	Off Peak	349	0.05	14.110	0.007	49.2
	Total	837	0.12			134.4
7	**Other (<100 kw)**	184	0.03	15.870	0.004	29.2
8	Total	710,971	100.00		13.544	96,293.2
9	Composite Cost of Purchased Energy				13.544 ¢/kwh	

Hawaii Electric Light Company, Inc.

DERIVATION OF TEST YEAR 2006
Puna Geothermal Venture Energy & Capacity Payments
Direct Testimony
Proposed Rates

	Energy Payments	On-Peak		Off-Peak	
1	Test Year 2006 KWh forecasted	131,263,864		90,212,536	
2	Hours	4384.6		3348.3	
3	KWH Energy min to 25 mw & 22 mw	109,384,059		73,507,804	
4	on&off peak base rate	6.56	cents/NET KWH	5.43	cents/NET KWH
5	avoided energy rate	17.45	cents/kwh	14.11	cents/kwh
6	Energy payments from Min. to 25 MW	$ 19,087,518		$ 10,371,951	
7	Total On-Peak and Off-Peak	$ 29,459,469			

	Above 25 mw			Above 22 mw	
	on-peak			off-peak	
8	Rate = [$.038/kwh * (PNW (current)/$.5444/gal)]+[$.0029*(GDP IPD (current)/(base))]			Rate = on-peak rate - $.01/kwh	
9	PNW (current)	1.8163			
10	GDP IPD (current) & (base)	112.5	92.3		
11	Rate	0.13032		Rate	0.12032
12	Energy above 25 mw	21,879,805		Energy above 22 mw	16,704,732
13	Energy payments above 25mw	$ 2,851,376		Energy payments above 22 mw	$ 2,009,913
14	Energy payments above 25/22 mw	$ 4,861,290			
15	**Total**	$ 34,320,759			

Capacity Payments

16	Firm Capacity		25000	kw				
17	Capacity Rate		160	$/kw-yr				
18							$	4,000,000
19	Additional Capacity (additional 5MW)		5000	kw				
20	Additional Capacity Rate		100.95	$/kw-yr				
21							$	504,750
22	**Total Capacity Payments**						$	**4,504,750**
23	Possible On-peak kwh		141,540,000	kwh				
24	Less Forecast on-peak kwh		(131,263,864)	kwh				
25	On-peak deficiency kwh		10,276,136					
26	Below 25 MW	15%	1,499,925	kwh at	0.0339	=	$	50,847
27	Between 25 to 35 MW	85%	8,499,575	kwh at	0.0214	=	$	181,891
28	Less Capacity Sanction						$	232,738

29 On-Peak Availability = (Total on-peak energy subject to its legally enforceable obligation) x 100
Divided by (4,718 on-peak hours)(30,000 kw firm capacity obligation)

OR $\frac{(131{,}540{,}500 \text{ kwh}) (100)}{(4{,}718 \text{ on-peak hrs}) (30{,}000 \text{ kw})}$ = 92.94 %

	Less Availabilty Factor Sanction Below 95%:	2.00	@ $7,992 =	$	15,984
30	**Adjusted Capacity Payments**			$	**4,256,028**

CA Reference:

Line 1: CA-WP-211, page 1
Line 2: HELCO-WP-545, page 2
Line 3: CA-WP-211, page 1
Line 4 and 5: HELCO-WP-545, page 2
Line 6: Line 5 x Line 3
Lines 8 to 10: HELCO-WP-545, page 2
Line 12: Line 1 - Line 3
Line 13: Line 12 x Line 11
Line 15: Line 14 + Line 7

Line 16 to 22: HELCO-WP-545, page 2
Line 23: 14 on-peak hours x 30,000 kw x 337 available days
Line 24: Subtract Line 1 kwh forecast
Line 25: Line 23 - Line 24
Lines 26 and 27: HELCO-WP-545, page 2
Line 28: Line 26 + Line 27
Line 29: HELCO-WP-545, page 2
Line 30: Line 22 - Line 28 - Line 29

Hawaii Electric Light Company, Inc.

Fuel Oil Expense for ECAC Calculations
2006 Test Year - Direct Testimony
At Present Rates

	Description	(A) Central Station - Steam: Shipman	(B) Central Station - Steam: Hill	(C) Central Station - Steam: Puna	(D) Total Steam Cols A + B + C)
1	MBtu Consumed	815,463	2,915,459	1,435,983	5,166,905
2	No. of Barrels Consumed	129,439	462,771	227,934	820,144
3	Wtd. Fuel Oil Price ($/bbl)	57.0902	57.0902	58.3389	
4	Fuel Additive	0.1479	0.1479	0.1479	
5	Petrospect	0.0869	0.0869	0.0869	
6	Propane	0.0000	0.0000	0.0000	
7	Total Fuel Price ($/bbl)	57.3250	57.3250	58.5737	
8	Heat Content (MBtu/bbl)	6.3	6.3	6.3	
9	Cost per MBtu (¢/MBtu) (line 7 + 8 x 100)	909.92	909.92	929.74	
	Fuel Expense				
10	Fuel Oil Price	7,389,674	26,419,694	13,297,408	47,106,776
11	Fuel Additive	19,145	68,448	33,713	121,306
12	Petrospect	11,246	40,207	19,803	71,256
13	Propane	-	-	-	-
14	Fuel Expense ($)	7,420,065	26,528,349	13,350,924	47,299,338

	Description	(E) Central Station - Diesel: Waimea	(F) Central Station - Diesel: Kanoelehua	(G) Central Station - Diesel: Keahole	(H) Central Station - Diesel: Puna CT3	(I) Total Diesel Cols E+F+G+H)
15	MBtu Consumed	6,626	48,551	1,586,357	200,963	1,842,497
16	No. of Barrels Consumed	1,131	8,285	270,709	34,294	314,419
17	Wtd. Fuel Oil Price ($/bbl)	87.7341	86.7252	88.0456	86.7656	
18	Heat Content (MBtu/bbl)	5.86	5.86	5.86	5.86	
19	Cost per MBtu (¢/MBtu) (line 17 + 18 x 100)	1,497.17	1,479.95	1,502.48	1,480.64	
20	Fuel Expense ($)	99,206	718,534	23,834,757	2,975,539	27,628,036

	Description	(J) Total Central Station (Cols D + I)	(K) Wind	(L) Hydro	(M) Total Wind + Hydro (Cols K + L)	(N) Total Gen + Wind + Hydro (Cols J + M)	(O) Dispersed	(P) Total Gen + Wind/Hydro + Dispersed (Cols N + O)
21	MBtu Consumed	7,009,402	22,592	341,129	363,721	7,373,123	1,703	7,374,827
22	No. of Barrels Consumed	1,134,563				1,134,563	291	1,134,854
23	Fuel Price ($/bbl)		0.0000	0.0000			94.0338	
24	Heat Content (MBtu/bbl)						5.86	
25	Cost per MBtu (¢/MBtu) (line 23 + 24 x 100)						1,604.67	
26	Fuel Expense ($)	74,927,374	-	-	-	74,927,374	27,330	74,954,704

Line 1: CA-WP-204, page 3
Line 2: Line 1 + Line 8
Line 3: CA-204, page 1, column (E)
Line 7: Sum of Lines 3 through 6
Line 10: Line 1 x Line 3
Line 11: Line 1 x Line 4
Line 12: Line 1 x Line 5
Line 13: Line 1 x Line 6
Line 14: Sum of Lines 10 through 13
Line 15: CA-WP-204, page 3
Line 16: Line 15 + Line 18
Line 17: CA-204, page 1, column (E)
Line 20: Line 15 x Line 17 + Line 18
Line 21: CA-WP-204, page 3
Line 23: CA-204, page 1
Line 24: Line 21 x Line 23 + Line 24

Hawaii Electric Light Company, Inc.
Determination of Percent to System Kwh Mix
2006 Test Year - Direct Testimony
At Present Rates

Line		(A) 2006 Norm Energy (Mwh)	Reference
	Net Generation (Mwh)		
1	Shipman	48,391	CA-WP-204, page 3
2	Hill	223,331	CA-WP-204, page 3
3	Puna	88,552	CA-WP-204, page 3
4	Waimea	597	CA-WP-204, page 3
5	Kanoelehua	3,980	CA-WP-204, page 3
6	Keahole	132,942	CA-WP-204, page 3
7	Puna CT3	15,850	CA-WP-204, page 3
8	Wind	1,656	CA-WP-204, page 1
9	Hydro	24,998	CA-WP-204, page 1
10	Dispersed	128	CA-WP-204, page 3
11	Total	540,425	
	Purchased Power (Mwh)		
12	HEP	421,930	CA-WP-204, page 1
13	PGV	221,476	CA-WP-204, page 1
14	Other	67,574	CA-WP-204, page 1
15	Total	710,981	

		(A) 2006 Norm Energy (Gwh)	(B) % to Total System
	Total Net System		
16	Net Generation	540.4	43.18
17	Purchase Power	711.0	56.82
18	Total Net System	1,251.4	100.00

Hawaii Electric Light Company, Inc.
Determination of Percent of Generation Mix,
Fuel Price by Plant (in ¢/mbtu) and
Composite Cost of Generation (in ¢/mbtu)
2006 Test Year - Direct Testimony
At Present Rates

Line	Generation	(A) MBTU	(B) % to Total Generation
1	Shipman	815,463	11.06
2	Hill	2,915,459	39.53
	subtotal -Hilo	3,730,922	50.59
3	Puna	1,435,983	19.47
4	Steam total	5,166,905	70.06
5	Waimea	6,626	0.09
6	Kanoelehua	48,551	0.66
7	Keahole	1,586,357	21.51
8	Puna CT3	200,963	2.72
9	Diesel total	1,842,497	24.98
10	Wind	22,592	0.31
11	Hydro	341,129	4.63
12	Wind/Hydro total	363,721	4.93
13	Total-Steam, Diesel, Wind/Hydro	7,373,123	99.98
14	Dispersed	1,703	0.02
15	Total Generation	7,374,827	100.00

	Generation	(C) Fuel Expense ($)	(D) Fuel Price (¢/mbtu)
16	Shipman	7,389,723	909.92
17	Hill	26,419,872	909.92
18	subtotal - Hilo	33,809,595	906.20
19	Puna	13,297,491	929.74
20	Steam total	47,107,086	911.71
21	Waimea	99,206	1497.17
22	Kanoelehua	718,537	1479.95
23	Keahole	23,834,868	1502.48
24	Puna CT3	2,975,553	1480.64
25	Diesel total	27,628,164	1499.50
26	Wind	0	0.00
27	Hydro	0	0.00
28	Wind/Hydro total	0	0.00
29	Total-Steam, Diesel, Wind/Hydro	74,735,250	1013.62
30	Dispersed	27,330	1604.67
	Total Generation	74,762,580	1013.87

CA Reference:
Column A: CA-WP-204, page 2
Column C: CA-WP-204, page 3
Column D: CA-WP-215, page 1

Hawaii Electric Light Company, Inc.
% of Steam, Diesel and Wind/Hydro to Central Station+Hydro/Wind Kwh Mix
2006 Test Year - Direct Testimony
At Proposed Rates

Line		(A) 2006 Norm Energy (Mwh)	(B) % to Total Generation	CA Reference
	Central Station+Wind/Hydro Net Generation (Mwh)			
1	Shipman	48,391		CA-WP-204, page 3
2	Hill	223,331		CA-WP-204, page 3
3	Puna	88,552		CA-WP-204, page 3
4	Steam total (lines 1+2+3)	360,274	66.68	
5	Waimea	597		CA-WP-204, page 3
6	Kanoelehua	3,980		CA-WP-204, page 3
7	Keahole	132,942		CA-WP-204, page 3
8	Puna CT3	15,850		CA-WP-204, page 3
9	Diesel total (lines 4+5+6+7)	153,370	28.39	
10	Wind	1,656		CA-WP-204, page 1
11	Hydro	24,998		CA-WP-204, page 1
12	Wind/Hydro total (lines 8+9)	26,653	4.93	
13	Total Central Station+Wind/Hydro	540,296	100.00	
14	Dispersed Generation	128		CA-WP-204, page 3

Hawaii Electric Light Company, Inc.
Net System % Mix
2006 Test Year - Direct Testimony
At Proposed Rates

		(A) 2006 Norm Energy (Gwh)	(B) % to Total System
	Central Station Generation		
1	Steam	360.3	28.79
2	Diesel	153.4	12.26
3	Totl Central Station	513.7	41.05
4	Wind/Hydro	26.7	2.14
5	Totl Cen Stn + Wind/Hydro	540.4	43.19
6	Dispersed Generation	0.1	0.01
7	Purchase Power	711.0	56.81
8	Total Net System	1,251.5	100.01

CA Reference:
Column (A): CA-WP-215, page 5

Hawaii Electric Light Company, Inc.
Percent of Central Station+Wind/Hydro
and DG to Total Generation Mbtu Mix
2006 Test Year - Direct Testimony
At Proposed Rates

		(A) 2006 Mbtu Consumed	(B) % to Total Mbtu Consumed
1	Central Station+Wind/Hydro Gen.	7,373,123	99.98
2	DG	1,703	0.02
3	Total Generation	7,374,827	100.00

CA *Reference:*
Column (A): CA-WP-215, page 3

Hawaii Electric Light Company, Inc.
Determination of Composite Cost of DG Energy
2006 Test Year - Direct Testimony

At Proposed Rates

	(A)	(B)	(C)	(D)	(E) (colD ÷ colC x 100)	(F) (colD ÷ colB x 100)
Line	DG Unit Location	Net to System (Kwh)	Fuel Consumed (Mbtu)	Fuel Expense ($)	Fuel Cost (¢/mbtu)	Fuel Cost (¢/kwh)
1	Dispersed Gen.	128,325	1,703	27,330	1604.66	21.298
2					0.00	0.000
3					0.00	0.000
4					0.00	0.000
5	Total	128,325	1,703	27,330	1604.66	21.298

Line		
6	Composite DG Fuel Cost	1604.66 ¢/mbtu
7	Composite Cost of DG Energy	21.298 ¢/kwh

CA Reference:
Column (B): CA-WP-215, page 5
Column (C): CA-WP-215, page 1
Column (D): CA-WP-215, page 1

Hawaii Electric Light Company, Inc.
DG and Purchased Energy Loss Factor Calculations
2006 Test Year - Direct Testimony
At Proposed Rates

Line			Reference
1	Net to System (gwh)	1,251.4	CA-203, Line 5
2	Sales (gwh)	1,148.0	CA-203, Line 1
3	DG & Purch. Pwr Loss Factor	1.090	Line 1 ÷ Line 2

HAWAII ELECTRIC LIGHT COMPANY, INC.
Composite Cost of Generation
2006 Test Year - Direct
At Proposed Rates

Line	CENTRAL STATION GENERATION COMPONENT	
	FUEL PRICES, ¢/mmbtu	
1	Shipman Industrial	909.92
2	Hill Industrial	909.92
3	Puna Industrial	929.74
4	Keahole Diesel	1,502.48
5	Waimea Diesel	1,497.17
6	Kanoelehua Diesel	1,479.95
7	Puna Diesel	1,480.64
8	Wind	0.00
9	Hydro	0.00
	BTU MIX, %	
10	Shipman Industrial	11.06
11	Hill Industrial	39.53
12	Puna Industrial	19.47
13	Keahole Diesel	21.51
14	Waimea Diesel	0.09
15	Kanoelehua Diesel	0.66
16	Puna Diesel	2.72
17	Wind	0.31
18	Hydro	4.63
		99.98
19	COMPOSITE COST OF GENERATION, ¢/mmbtu	1,015.99

Lines 1-18: CA-WP-215, page 3
Line 19: (Line 1x10 + line 2x11 + line 3x12 + line 4x13 + line 5x14 + line 6x15 + line 7x16 + line 8x17 + line 9x18)